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Monsanto Research Corp.
Dayton, OH

Prepared for

Industrial Environmental Research Lab.
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16. ABSTRACT The report describes and assesses the potential impact of air emissions, wastewater effluents, and solid wastes from the operation of dry bottom industrial boilers firing pulverized bituminous coal. Air emissions were characterized by a literature survey and field sampling. Significant emissions resulting from coal combustion were particulate matter, sulfur oxides (SOx), nitrogen oxides (NOx), hydrocarbons, polycyclic organic materials (POM), and a number of elements. The potential environmental impact of each emission species after passing through state-of-the-art controls was individually assessed using a calculated quantity known as the source severity. Species determined to have source severities greater than 1.0 were NOx (1.7), SOx (2.2), and POM (6.0). Pollutant concentrations were also measured in wastewater and solid waste streams. Effluent source severities were found to be significantly less than 1.0 for most species. The potential impact of solid waste discharges on the quality of air and of ground and surface water was also found to be minor when available controls were applied.

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PREFACE

The Industrial Environmental Research Laboratory (IERL) of the U.S. Environmental Protection Agency (EPA) has the responsibility for insuring that pollution control technology is available for stationary sources to meet the requirements of the Clean Air Act, the Federal Water Pollution Control Act, and solid waste legislation. If control technology is unavailable, inadequate, or uneconomical, then financial support is provided for the development of the needed control techniques for industrial and extractive process industries. Approaches considered include: process modifications, feedstock modifications, add-on control devices, and complete process substitution. The scale of the control technology programs ranges from bench- to full-scale demonstration plants.

The Chemical Processes Branch of the Industrial Processes Division of IERL has the responsibility for developing control technology for a large number of operations (more than 500) in the chemical industries. As in any technical program, the first question to answer is, "Where are the unsolved problems?" This is a determination which should not be made on superficial information; consequently, each of the industries is being evaluated in detail to determine if there is, in EPA's judgment, sufficient environmental risk associated with the process to indicate that pollution reduction is necessary. This report contains the data necessary to make that decision for air emissions, water effluents, and solid residues from dry bottom industrial boilers firing pulverized bituminous coal.

Monsanto Research Corporation has contracted with EPA to investigate the environmental impact of various industries which represent sources of pollution in accordance with EPA's responsibility as outlined above. Dr. Robert C. Binning serves as Program Manager in this overall program, entitled "Source Assessment," which includes the investigation of sources in each of four categories: combustion, organic materials, inorganic materials, and open sources. Dr. Dale A. Denny of the Industrial Processes Division at Research Triangle Park serves as EPA Project Officer. In this study of dry bottom industrial boilers firing pulverized bituminous coal, Dr. Ronald A. Venezia served as EPA Task Officer.

ABSTRACT

This report describes and assesses the potential impact of air emissions, wastewater effluents, and solid wastes resulting from the operation of dry bottom industrial boilers firing pulverized bituminous coal. Consuming approximately 2.3 x 10^7 metric tons of such coal per year, this source type constitutes the primary method of firing coal in industrial boilers.

Air emissions were characterized by a literature survey and a field sampling program. Significant emissions resulting from coal combustion were particulate matter, sulfur oxides, nitrogen oxides, hydrocarbons, polycyclic organic materials, and a number of elements emitted as particles and vapors. The potential environmental impact of each emission species after passing through state-of-the-art controls was individually assessed using a calculated quantity known as the source severity. This quantity is the ratio of the maximum ground level concentration, as determined through dispersion equations, to a potentially hazardous concentration. Species determined to have source severities greater than 1.0 were nitrogen oxides (1.7), sulfur oxides (2.2), and polycyclic organic materials (6.0). Estimates of the human population around an average source in this category exposed to a severity greater than 1.0 ranged from 1,225 persons for nitrogen oxides to 7,536 persons for polycyclic organic materials.

Pollutant concentrations were also measured in wastewater and solid waste streams. Effluent source severities, defined as the ratio of the concentration of a pollutant in the receiving water after dispersion to a potentially hazardous concentration, were found to be significantly less than 1.0 for most species. The potential impact of solid waste discharges on the quality of air and of ground and surface water was also found to be minor when available controls are applied.

This report, submitted under Contract No. 68-02-1874 by Monsanto Research Corporation under the sponsorship of the U.S. Environmental Protection Agency, covers the period from August 1974 through June 1979.

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ABBREVIATIONS AND SYMBOLS

a...f -- constants used in dispersion equations
A -- ash percent of coal
AA -- atomic absorption
A...F -- atmospheric stability classes
A_a -- area containing the affected population, km²
AAQS -- ambient air quality standard
A_R -- ratio $Q/ac\pi u$
ASTM -- American Society for Testing and Materials
BOD -- biological oxygen demand
B_R -- ratio $-H^2/2c^2$
C -- confidential
$C_{1,2...n}$ -- organic molecules containing from 1 to n carbon atoms
CC -- centrifugal collector
C_D -- concentration of a pollutant in an effluent, g/m³
CM -- combustion modification
CO -- carbon monoxide
COD -- chemical oxygen demand
DC -- direct current
D_p -- population density, persons/km²
e -- 2.72
EF -- emission factor, g/kg
ESP -- electrostatic precipitator
exp -- exponent of e
F -- hazard factor, g/m³
F_e -- effluent hazard factor, g/m³
FF -- fabric filter
FGD -- flue gas desulfurization
FGT -- flue gas treatment
F_{MZ} -- fraction of river flow in a mixing zone
GC -- gravity collector
GC-MS -- gas chromatography-mass spectroscopy
H -- height of emission release, m
ICAP -- inductively coupled argon plasma
LC_{50}(96-hr) -- concentration lethal to 50% of a group of test organisms in a 96-hr period, g/m³
M -- molar
NEDS -- National Emissions Data System
NO_x -- nitrogen oxides
NPDES -- National Pollutant Discharge Elimination System

ABBREVIATIONS AND SYMBOLS (continued)

NSPS -- new source performance standards
OPEC -- oil producing and exporting countries
P' -- total affected population
PCB -- polychlorinated biphenyls
pH -- negative log of the hydrogen ion concentration
POM -- polycyclic organic materials
ppm -- parts per million
Q -- emission rate, g/s
R -- rate of fuel flow
S -- percent of sulfur content of coal
S_a -- source severity of air pollutant emissions
S_{AMZ} -- effluent source severity after the mixing zone
SASS -- source assessment sampling system
S_{BD} -- effluent source severity before dilution
S_{CO} -- source severity of carbon monoxide emissions
S_e -- source severity of an effluent species
S_{HC} -- source severity of hydrocarbon emissions
S_{MZ} -- effluent source severity in the mixing zone
S_{NO_2} -- source severity of nitrogen dioxide emissions
SO_x -- sulfur oxides
S_P -- source severity of particulate emissions
S_{SO_2} -- source severity of sulfur dioxide emissions
t -- averaging time, min
t_o -- short-term averaging time, (3 min)
T.C. -- thermocouple
TDS -- total dissolved solids, g/m^3
TLV -- threshold limit value, g/m^3
TS -- total solids, g/m^3
TSS -- total suspended solids, g/m^3
u -- wind speed, m/s
$\bar{u}$ -- average wind speed, m/s
USGS -- United States Geological Survey
vr -- river flow rate, m^3/s
V_R -- minimum river flow rate, m^3/s
WS -- wet scrubber
x -- downwind emission dispersion distance from source of emission release, m
XAD-2 -- resin used for trapping organic emissions
y -- horizontal distance from centerline of dispersion, m

ABBREVIATIONS AND SYMBOLS (continued)

π -- 3.1416

σ_y -- standard deviation of horizontal dispersion, m

σ_z -- standard deviation of vertical dispersion, m

$\bar{\chi}$ -- time-averaged ground level concentration of an emission, g/m^3

χ_{max} -- instantaneous maximum ground level concentration, g/m^3

$\bar{\chi}_{max}$ -- time-averaged maximum ground level concentration, g/m^3

SECTION 1

INTRODUCTION

The purpose of this study was to characterize air emissions, water effluents, and solid residues resulting from the combustion of pulverized bituminous coal in industrial dry bottom boilers. The report contains a source description that defines process operations, process chemistry, plant capacity, and source locations. The multimedia emissions characterization identifies all emission points and emission species, determines their emission rates, and evaluates the potential environmental effect due to their release. Present and emerging control technologies are also considered. The final sections of the report discuss the growth and nature of the source type and unusual results of this study.

A general indication of the size and position of this source type within all combustion sources is shown in Figures 1 through 3 (1). From Figure 1, industrial combustion is the second largest consumer of fossil fuel, representing 29% of national fossil fuel consumption. Within the industrial boiler sector, coal is the third largest energy source, representing 16% of industrial fuel consumption. All three coals (anthracite, bituminous, and lignite) are used in industrial boilers, but bituminous is the primary fuel (96%). Within bituminous coal-fired industrial boilers, pulverized dry bottom units represent nearly half (49%) of all fuel consumption, followed in order of decreasing fuel consumption by stokers, pulverized wet bottom units, and cyclones. Overall this source type consumes 7.8% of the fossil fuel used in industrial boilers and 2.3% of the total quantity of fossil fuels used for the generation of power or heat in the United States (1).

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(1) Surprenant, N., R. Hall, S. Slater, T. Susa, M. Sussman, and C. Young. Preliminary Environmental Assessment of Conventional Stationary Combustion Systems; Volume II, Final Report. EPA-600/2-76-046b (PB 252 175)[a], U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, March 1976. 557 pp.

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[a] This number designates the National Technical Information System (NTIS) access number.

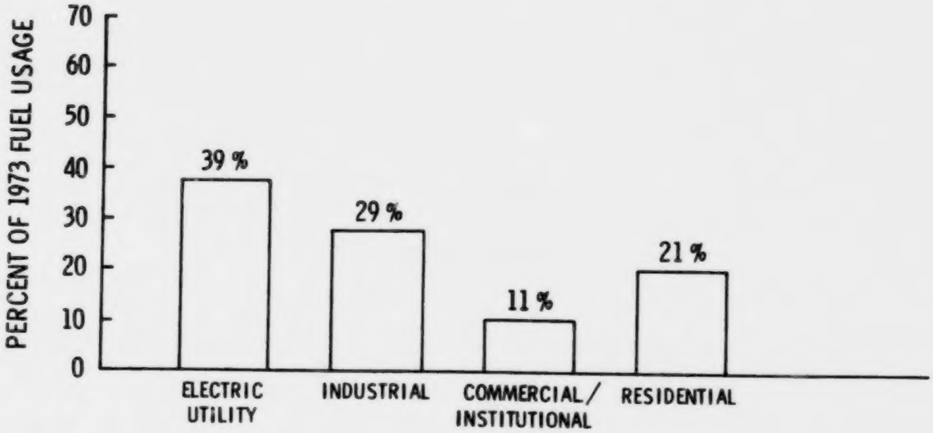

Figure 1. Fossil fuel consumption by end use (1).

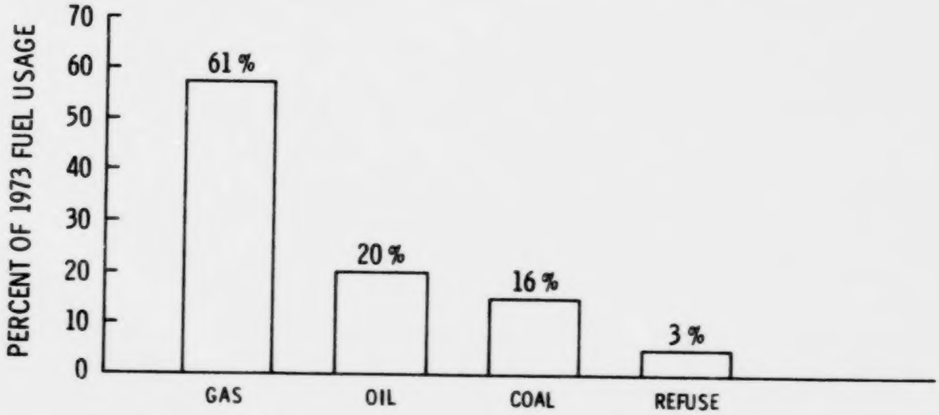

Figure 2. Distribution of industrial boiler fuel types (1).

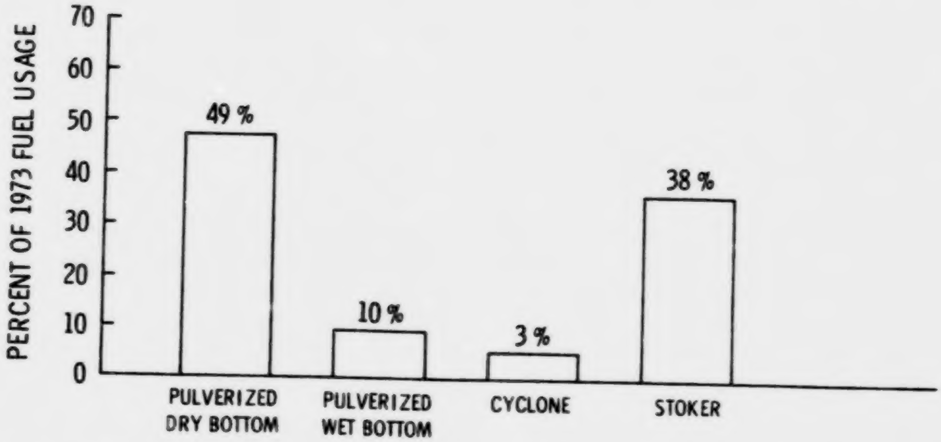

Figure 3. Distribution of coal-fired industrial boiler designs (1).

SECTION 2

SUMMARY

This document characterizes and assesses the potential impact of air emissions, wastewater effluents, and solid residues released to the environment by dry bottom industrial boilers firing pulverized bituminous coal. This source is defined as all boilers (steam generators) that meet each of the following criteria:

- The primary fuel is pulverized bituminous coal.
- The operating temperature of the furnace is kept below the ash fusion temperature so that ash remaining in the furnace can be removed as a dry powder (dry bottom).
- The boiler is owned and operated by the industrial sector to produce steam for use at an industrial site.

The source category consumes 685 x 10^6 GJ/yr (approximately 2.3 x 10^7 metric tons[a]/yr) of bituminous coal and represents about 9% of the total steam-generating capacity of U.S. industry and approximately 49% of the industrial steam generated by coal combustion. States containing ≥5% of the boiler population are listed in Table 1. Capacities of the individual boilers considered in this assessment range from 1 GJ/hr to 1,900 GJ/yr and average 222 GJ/hr.

Over 99% of the air emissions result from coal combustion in the furnace and are emitted from the boiler stack. Other emissions arise from coal storage and handling, cooling towers when used, and ash handling and disposal. Major emissions are the criteria pollutants; particulates, sulfur oxides (SO_x), nitrogen oxides (NO_x), hydrocarbons, and carbon monoxide (CO). Polycyclic organic materials (POM) are among the hydrocarbon species emitted. In addition trace elements are emitted as part of the particulate or in the vapor phase. The percent contribution of this source to the total state emission burdens of criteria pollutants are shown in Table 2 for the states included in the National Emissions Data System (NEDS) file.

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[a] 1 metric ton = 10^6 grams; conversion factors and metric system prefixes are presented at the end of this report.

TABLE 1. STATES CONTAINING ≥5% OF THE TOTAL NUMBER OF BOILERS AS DEFINED FOR THIS SOURCE CATEGORY

State	Percentage of boilers	Percentage of fuel consumption
Ohio	19	15
Pennsylvania	13	9
North Carolina	9.5	2
Michigan	6.6	10
New York	6.6	4
Illinois	6.4	7
Tennessee	5.9	3
Virginia	5.5	4
Indiana	5.0	8
Iowa	5.0	2
Total	82.5	64

TABLE 2. PERCENT CONTRIBUTION OF THIS SOURCE TO TOTAL STATE EMISSIONS OF CRITERIA POLLUTANTS

	Percent contribution				
State	Particulate matter	SO_x	NO_x	Hydrocarbon	CO
Alabama	<0.01	0.2	0.3	<0.01	<0.01
Georgia	0.5	1.2	0.2	<0.01	<0.01
Idaho	4.7	3.3	3.2	0.02	<0.01
Illinois	2.6	2.0	0.8	<0.01	<0.01
Indiana	0.2	1.0	0.5	0.2	0.01
Iowa	1.8	9.1	3.6	0.1	0.01
Kansas	<0.01	0.3	0.02	<0.01	<0.01
Kentucky	0.3	0.6	0.4	<0.01	<0.01
Maryland	0.1	4.1	2.3	0.02	<0.01
Massachusetts	0.7	0.06	0.03	<0.01	<0.01
Michigan	0.8	2.1	0.9	0.2	0.04
Minnesota	0.2	0.2	0.08	<0.01	<0.01
Missouri	3.7	0.6	0.4	<0.01	<0.01
New York	4.3	7.7	1.1	<0.01	<0.01
North Carolina	2.4	4.9	2.3	0.09	0.04
Ohio	2.6	2.8	1.7	0.01	<0.01
Oregon	0.3	3.5	0.6	<0.01	<0.01
Pennsylvania	2.0	2.5	0.4	0.05	0.06
Tennessee	3.6	1.9	2.9	0.08	0.04
Utah	7.8	1.1	1.6	0.03	0.02
Virginia	8.5	10.5	5.1	0.09	0.05
Washington	0.2	0.1	0.05	<0.01	<0.01
West Virginia	0.7	0.9	1.0	0.08	0.04
Wisconsin	1.8	1.1	0.3	0.02	0.02
Wyoming	0.5	3.6	2.5	0.01	<0.01

Particulate emissions are controlled on approximately 62% of the sources according to the NEDS file for this source type. Particulate controls applied to these boilers are centifugal collectors (57% of controls), electrostatic precipitators (26%), fabric filters (7%), gravity collectors (6%), and wet scrubbers (4%). Collection efficiencies of these devices reported to NEDS by industry are shown in Table 3. It should be noted that the upper range limits reported for centrifugal and gravity collectors appear to be unrealistically high, and thus may be in error. About 14% of the boilers use multiple particulate controls, and about 1% are equipped with SO_x controls. Controls for NO_x emissions are under development.

TABLE 3. EFFICIENCIES OF PARTICULATE CONTROL DEVICES APPLIED TO DRY BOTTOM INDUSTRIAL BOILERS FIRING PULVERIZED BITUMINOUS COAL, AS REPORTED IN NEDS

Control device	Collection efficiencies, %	
	Range	Average
Centrifugal collector	25.0 to 99.3[a]	79
Gravity collectors	25.0 to 85.0	56
Electrostatic precipitator	71.9 to 99.5	96
Fabric filters	46.5 to 99.5	91
Wet scrubbers	60.0 to 99.0	81

[a] Upper end of range is high and may be in error.

In order to evaluate the potential environmental effect of air emissions from an average source in this category, a source severity, S, was defined as the ratio of the time-averaged maximum ground level concentration ($\overline{\chi}_{max}$) to an appropriate hazard factor (F). The values of $\overline{\chi}_{max}$ were calculated from accepted plume dispersion equations and controlled emission factors determined by sampling an industrial boiler equipped with an electrostatic precipitator. The hazard factor is defined as the primary ambient air quality standard in the case of criteria pollutants (particulate matter, SO_x, NO_x, CO, and hydrocarbons) and as a reduced threshold limit value (TLV®), F = TLV x 8/24 x 1/100, for other pollutants. The factor 8/24 corrects for a 24-hr exposure while 1/100 is a safety factor.

Controlled emission factors and source severities calculated for an average size unit in this category (222 GJ/hr) are shown in Table 4. No CO was found at a detection limit of 1 ppm and no polychlorinated biphenyl (PCB) compounds were found in any of the air, water, or solid samples at a detection limit of 2.5 µg/kg.

TABLE 4. CONTROLLED EMISSION FACTORS, SOURCE SEVERITIES, AND AFFECTED POPULATIONS FOR THE AVERAGE SOURCE (222 GJ/hr)[a]

Emission species	Controlled emission factor, g/kg of coal	Source severity	Affected population for $S_a>1.0$	Affected population for $S_a>0.05$
Particulate matter	0.16A[b]	1.2×10^{-1}	0	2,500
NO_x	8.2[c]	1.7	1,200	42,000
SO_x	19S[c,d]	2.2	2,200	63,000
Sulfate	1.8×10^{-2}	9.8×10^{-2}	0	1,900
Hydrocarbons	2.5×10^{-2}[c]	4.0×10^{-3}	0	0
POM (total)	1.5×10^{-3}	4.1×10^{-2}	0	0
POM (carcinogenic)	1.1×10^{-3}	6.0	7,500	190,000
Elements:				
Aluminum	2.2×10^{-1}	1.2×10^{-1}	0	2,500
Arsenic	1.5×10^{-3}	1.6×10^{-2}	0	0
Antimony	1.6×10^{-2}	1.7×10^{-1}	0	3,900
Barium	4.1×10^{-3}	4.4×10^{-2}	0	0
Beryllium	2.5×10^{-5}	6.8×10^{-2}	0	1,000
Bismuth	$<1.0 \times 10^{-6}$[e]	5.4×10^{-7}	0	0
Boron	2.9×10^{-2}[f]	1.6×10^{-2}	0	0
Bromine	1.1×10^{-2}[f]	8.5×10^{-2}	0	1,500
Cadmium	4.8×10^{-4}	5.2×10^{-2}	0	560
Calcium	4.5×10^{-2}	4.9×10^{-2}	0	0
Cerium	1.4×10^{-4}[e]	7.6×10^{-5}	0	0
Cesium	2.5×10^{-4}[e]	6.8×10^{-4}	0	0
Chlorine	7.3×10^{-1}[f]	5.7×10^{-1}	0	15,000
Chromium	2.0×10^{-3}[g]	1.1×10^{-1}	0	2,200
Cobalt	1.7×10^{-3}	9.2×10^{-2}	0	1,700
Copper	2.8×10^{-3}	1.5×10^{-2}	0	0
Dysprosium	1.4×10^{-3}[f]	7.6×10^{-4}	0	0
Erbium	2.6×10^{-4}[f]	1.4×10^{-4}	0	0
Europium	5.9×10^{-6}[e]	3.2×10^{-6}	0	0
Fluorine	7.8×10^{-2}[f]	2.1×10^{-1}	0	5,000
Gadolinium	1.0×10^{-3}[f]	5.4×10^{-4}	0	0
Gallium	6.5×10^{-3}[f]	3.5×10^{-3}	0	0
Germanium	4.8×10^{-3}[f]	2.6×10^{-3}	0	0
Gold	$<1.0 \times 10^{-4}$[f]	5.4×10^{-5}	0	0
Hafnium	1.2×10^{-5}[e]	1.3×10^{-4}	0	0
Holumium	2.1×10^{-4}[f]	1.1×10^{-4}	0	0
Iodine	1.1×10^{-3}[f]	6.0×10^{-3}	0	0
Iridium	$<2.0 \times 10^{-4}$[f]	1.1×10^{-4}	0	0
Iron	1.9×10^{-1}[e]	2.1×10^{-1}	0	5,000
Lanthanum	9.3×10^{-5}[e]	5.0×10^{-5}	0	0
Lead	2.0×10^{-3}	7.2×10^{-2}	0	1,200
Lithium	2.7×10^{-2}[f]	1.5×10^{-2}	0	0
Lutenium	1.2×10^{-4}[f]	6.5×10^{-5}	0	0
Magnesium	2.0×10^{-2}	1.1×10^{-2}	0	0
Manganese	1.6×10^{-2}	1.7×10^{-2}	0	0
Mercury	5.0×10^{-5}	5.4×10^{-3}	0	0
Molybdenum	3.1×10^{-3}[f]	3.4×10^{-3}	0	0
Neodymium	1.2×10^{-2}[f]	6.5×10^{-3}	0	0
Nickel	1.5×10^{-3}[g]	8.1×10^{-2}	0	1,400
Niobium	5.4×10^{-5}[e]	2.9×10^{-5}	0	0

(continued)

TABLE 4 (continued)

Emission species	Controlled emission factor, g/kg of coal	Source severity	Affected population for $S_a > 1.0$	Affected population for $S_a > 0.05$
Osmium	$<2.0 \times 10^{-4}$[f]	5.4×10^{-1}	0	14,000
Palladium	$<1.0 \times 10^{-4}$[f]	5.4×10^{-5}	0	0
Phosphorus	1.7×10^{-2}	9.2×10^{-2}	0	1,700
Platinum	$<3.0 \times 10^{-4}$[f]	8.1×10^{-1}	0	22,000
Potassium	2.3×10^{-2}[e]	6.2×10^{-2}	0	870
Praeseodymium	2.1×10^{-3}[f]	1.1×10^{-3}	0	0
Rhenium	$<2.0 \times 10^{-4}$[f]	1.1×10^{-4}	0	0
Rodium	$<1.0 \times 10^{-4}$[f]	5.4×10^{-3}	0	0
Rubidium	3.7×10^{-2}[e]	2.0×10^{-4}	0	0
Ruthenium	$<1.0 \times 10^{-4}$[f]	5.4×10^{-5}	0	0
Samarium	1.9×10^{-5}[e]	1.0×10^{-5}	0	0
Scandium	5.1×10^{-5}[e]	2.8×10^{-5}	0	0
Selenium	1.6×10^{-3}	4.3×10^{-2}	0	0
Silicon	2.7×10^{-1}[e]	1.5×10^{-1}	0	3,200
Silver	8.5×10^{-4}	4.6×10^{-1}	0	12,000
Sodium	5.5×10^{-2}	1.5×10^{-1}	0	3,200
Strontium	4.4×10^{-3}	2.4×10^{-3}	0	0
Tantalum	9.5×10^{-6}[e]	1.0×10^{-5}	0	0
Tellurium	3.4×10^{-4}[f]	1.8×10^{-2}	0	0
Terbium	3.2×10^{-4}[f]	1.7×10^{-4}	0	0
Thallium	1.0×10^{-4}[f]	5.4×10^{-3}	0	0
Thorium	4.8×10^{-5}[e]	2.6×10^{-5}	0	0
Thulium	$<1.0 \times 10^{-4}$[f]	5.4×10^{-5}	0	0
Tin	1.3×10^{-2}	7.0×10^{-3}	0	0
Titanium	9.9×10^{-3}	5.4×10^{-3}	0	0
Tungsten	2.8×10^{-4}[f]	1.5×10^{-3}	0	0
Uranium	1.4×10^{-3}[f]	3.8×10^{-2}	0	0
Vanadium	4.0×10^{-3}	4.3×10^{-2}	0	0
Ytterbium	9.8×10^{-4}[e]	5.3×10^{-4}	0	0
Yttrium	1.1×10^{-4}[e]	6.0×10^{-4}	0	0
Zinc	4.2×10^{-3}	4.6×10^{-3}	0	0
Zirconium	4.0×10^{-4}[e]	5.4×10^{-4}	0	0

[a] Based on MRC sampling measurements made at a 130 GJ/hr industrial boiler and on literature data.

[b] Percent ash content of coal.

[c] Uncontrolled.

[d] Percent sulfur content of coal.

[e] Estimate based on the partitioning behavior of these elements, value = 1% of the average concentration in U.S. bituminous coal.

[f] Estimate based on 100% emission of the average concentration of this element in U.S. bituminous coal.

Another measure of potential environmental impact is the population which may be affected by emissions from an average source. The affected population is defined as the number of persons living in the area around an average size boiler where $\overline{\chi}$ (time-averaged ground level concentration) divided by F is greater than 1.0 or greater than 0.05. A $\overline{\chi}/F$ value of 1.0 indicates exposure to a potentially hazardous concentration of a pollutant; the value of 0.05 allows for inherent uncertainties in measurement techniques, dispersion modeling, and health effects data. Plume dispersion equations are used to find this area, which is then multiplied by an average population density to determine the affected population. The average population around an industrial boiler in this category is 470 persons/km². The populations affected by emissions having $\overline{\chi}/F$ greater than 1.0 and greater than 0.05 are also shown in Table 4.

Water usage in industrial boiler operations is highly variable. Waste streams common to most boilers in this category are boiler blowdown, wastes from feedwater treatment, and equipment cleaning wastes. Other waste streams which may or may not be present, depending on the boiler size, location and application, are once-through cooling water for steam condensation and equipment cooling, recirculating cooling water blowdown, sluicing water for ash transport, wash water from cleaning the steam used in pneumatic ash transport systems, and runoff from coal storage piles.

The potential impact of wastewater discharges was determined in a manner analogous to that used for air emissions. Effluent source severity, S_e, was defined as the ratio of the dispersed concentration of a pollutant in the receiving water (at minimum flow for rivers) to an effluent hazard factor. Water quality criterion values were used for hazard factors if available. If not, then $0.1[LC_{50}(96\text{-hr})]$ was used, for the aquatic species most sensitive to the pollutant of concern. Because of the large number of sites covered in this assessment, an average receiving body was defined as a river with an average flow of 725 m³/s and a minimum flow of 267 m³/s. These values were obtained by averaging U.S. Geological Survey (USGS) flow rate data for the rivers located near the boilers listed in NEDS. It should be noted that these flow rates varied by more than five orders of magnitude. Wastewater treatment practices for this source are not covered in the literature, but there is some indication that most sources discharge to municipal sewer systems or to onsite treatment facilities. Effluent factors, concentrations, and severities for a combined, uncontrolled wastewater stream for an average boiler are shown in Table 5, including values for total dissolved solids (TDS), total suspended solids (TSS), and total solids (TS).

Solid wastes generated are coal ash, SO_x scrubber sludge, and water treatment sludges. Of these, coal ash is the primary waste (>99%), although SO_x scrubber sludges will become a major waste

TABLE 5. EFFLUENT FACTORS, EFFLUENT CONCENTRATIONS, AND EFFLUENT SOURCE SEVERITIES FOR A COMBINED WASTE STREAM FOR AN AVERAGE SOURCE (222 GJ/hr)[a]

Pollutant	Effluent factor, g/kg of coal	Concentration in effluent, g/m^3	Effluent source severity
Acidity (as $CaCO_3$)	7.3×10^{-3}	4.8	2.9×10^{-6}
Alkalinity (as $CaCO_3$)	5.1×10^{-1}	3.3×10^{2}	2.0×10^{-4}
Ammonia	0[b]	$<5.0 \times 10^{-2}$	0
Hardness (as $CaCO_3$)	4.2	2.8×10^{3}	4.5×10^{-4}
Nitrate	1.1×10^{-2}	7.3	8.9×10^{-6}
Phenol	1.4×10^{-5}	9.0×10^{-3}	1.1×10^{-4}
PCB	0[b]	–[c]	0
POM	0[b]	–[c]	0
Sulfate	8.8×10^{-1}	4.8×10^{2}	2.8×10^{-5}
Sulfite	0[b]	<2.0	0
TDS	2.0×10^{1}	1.3×10^{4}	6.5×10^{-4}
TSS	9.2×10^{-1}	6.1×10^{2}	3.0×10^{-4}
TS	2.1×10^{1}	1.4×10^{4}	6.2×10^{-4}
Elements:			
Aluminum	2.5×10^{-2}	1.6×10^{1}	2.4×10^{-5}
Antimony	7.1×10^{-4}	4.7×10^{-1}	2.5×10^{-5}
Arsenic	2.8×10^{-4}	1.8×10^{-1}	4.5×10^{-5}
Barium	2.4×10^{-3}	1.6	1.9×10^{-5}
Beryllium	2.6×10^{-5}	1.7×10^{-2}	1.9×10^{-5}
Boron	8.1×10^{-4}	5.3×10^{-1}	8.7×10^{-6}
Cadmium	1.1×10^{-5}	7.3×10^{-3}	8.9×10^{-6}
Calcium	6.2×10^{-1}	4.1×10^{2}	3.1×10^{-3}
Chromium	2.8×10^{-4}	1.8×10^{-1}	4.5×10^{-5}
Cobalt	1.0×10^{-4}	6.7×10^{-2}	1.0×10^{-4}
Copper	3.4×10^{-4}	2.2×10^{-1}	2.7×10^{-6}
Iron	7.2×10^{-3}	4.7	1.9×10^{-4}
Lead	1.1×10^{-3}	7.0×10^{-1}	1.7×10^{-4}
Magnesium	4.5×10^{-1}	3.0×10^{2}	7.0×10^{-3}
Manganese	8.5×10^{-5}	5.6×10^{-2}	1.4×10^{-5}
Mercury	0[b]	$<2.0 \times 10^{-3}$	0
Molybdenum	6.1×10^{-4}	4.0×10^{-1}	1.7×10^{-5}
Nickel	2.8×10^{-3}	1.9	1.8×10^{-2}
Phosphorus	1.8×10^{-2}	1.2×10^{1}	1.4×10^{-1}[d]
Selenium	1.5×10^{-5}	9.9×10^{-3}	1.2×10^{-5}
Silicon	4.0×10^{-2}	2.6×10^{1}	1.3×10^{-5}
Silver	4.2×10^{-4}	2.8×10^{-1}	6.8×10^{-5}
Sodium	4.5	3.0×10^{3}	1.5×10^{-4}
Strontium	1.5×10^{-2}	1.0×10^{1}	5.0×10^{-7}
Tin	5.5×10^{-4}	3.4×10^{-1}	4.4×10^{-4}
Titanium	4.9×10^{-4}	3.2×10^{-1}	5.2×10^{-6}
Vanadium	3.4×10^{-3}	2.2	4.9×10^{-5}
Zinc	4.4×10^{-4}	2.9×10^{-1}	7.1×10^{-7}
Zirconium	0[b]	<2.0	0

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[a] Based on MRC sampling measurements made at a 130 GJ/hr industrial boiler.

[b] Not detected in any of the waste streams.

[c] Detection limits vary depending on the compound of interest but are in the microgram per liter range.

[d] Based on the hazard factor for elemental phosphorus, although the most likely form is relatively nontoxic phosphate.

if more stringent and/or comprehensive SO_x regulations are established. The environmental impact of solid wastes from this source type is dependent on the disposal method used and the characteristics of the disposal site, which are variable. Studies show that the potential effects of leaching are minimal due to the ion exchange capacity of most soils and that adequate controls are available in the form of ash and sludge fixation and/or the use of lined disposal areas.

The total design capacity of boilers covered in this assessment is expected to increase at an annual rate of 3.0% to 4.0% through 1990. Forecasts beyond this period are unreliable.

SECTION 3

SOURCE DESCRIPTION

The source type covered in this assessment is entitled dry bottom industrial boilers firing pulverized bituminous coal. This section defines the source type, characterizes the United States population of the source, and describes the processes of steam generation and combustion as they relate to the source.

SOURCE DEFINITION

For the purposes of this study, dry bottom industrial boilers firing pulverized bituminous coal are defined as all boilers (steam generators) which meet each of the following criteria:

- The primary fuel is pulverized bituminous coal.
- The operating temperature of the furnace is kept below the ash fusion temperature so that ash remaining in the furnace can be removed as a dry powder (hence the term dry bottom).
- The boiler is owned and operated by the industrial sector to produce steam for use at an industrial site.

Bituminous coals include both bituminous and subbituminous coal ranks as defined by the American Society for Testing and Materials (2). Both coal types are considered together because the coal production and consumption data utilized in this report are generally reported as bituminous coal.

Feed coal for this source type is pulverized into a fine powder, 70% of which will pass through a 200-mesh screen (3). Pulverizing coal facilitates injection into the boiler and mixture with combustion air for better combustion. For systems of this type, secondary fuels such as natural gas or fuel oil are often used during start-up to maintain stable ignition until operating temperatures are reached.

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(2) Standard Specification for Classification of Coals by Rank, Designation D 388-66 (Reapproved 1972). In: 1976 Annual Book of ASTM Standards, Part 26: Gaseous Fuels; Coal and Coke; Atmospheric Analysis. American Society for Testing and Materials, Philadelphia, Pennsylvania, 1976. pp. 211-214.

(3) The Study of Electricity, Your Trip Through Frank M. Tait Station. The Dayton Power and Light Co., April 1964. 22 pp.

The word "boiler" refers, in a strict sense, to the pressure vessel in which water is heated and/or converted to steam. In this study, the term is used to denote a complete system including all of the process operations and onsite facilities involved in the operation of external combustion, dry bottom industrial boilers firing pulverized bituminous coal, with one exception. Coal storage piles have already been assessed as an emission source (4) and therefore are not considered here. Support facilities and operations addressed in this source assessment include: boiler feedwater treatment, fuel and ash conveying, air and water pollution control, and solid waste disposal.

Source Inventory

A complete national inventory for industrial dry bottom boilers firing pulverized bituminous coal, as defined in this study, is not available. Consequently, the boiler population must be estimated from the available data using various assumptions. This is a difficult task because of the conflicting information in the literature.

Industrial boiler populations have been estimated in a number of reports; however, the estimates have varied because of the different assumptions used (1,5-7). In addition, these current population estimates contain many inconsistencies. For example, an EPA report prepared by GCA/Technology Division (1) estimates a fuel consumption of 79 TJ/hr with a design capacity of 348 TJ/hr steam for industrial bituminous pulverized dry bottom boilers. If the boiler efficiency is 90%, then the utilization factor must be 20%. Based on a study by Ehrenfeld, et al (8), a utilization of 20% is typical of industrial boilers firing less than 106 GJ/hr. However, another reference (9) states that below 106 GJ/hr, stokers are more economical than pulverizers. Thus one report predicts a 20% utilization for this source category, while other evidence contradicts it.

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(4) Blackwood, T. R., and R. A. Wachter. Source Assessment: Coal Storage Piles. EPA-600/2-78-004k (PB 284 297), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, May 1978. 98 pp.

(5) NEDS Condensed Point Source Listing for Particulate for all Values Greater than or Equal to 100 Short Tons of Emissions Per Year: SCC 1-02-002-02, SCC 1-02-002-08, SCC 1-02-002-12. Generated by U.S. Environmental Protection Agency, Durham, North Carolina, May 20, 1977.

(6) Barrett, R. E., A. A. Putnam, E. R. Blosser, and P. W. Jones. Assessment of Industrial Boiler Toxic and Hazardous Emissions Control Needs, Draft Report. Contract 68-02-1323, Task 8, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, August 1974. 18 pp.

(7) Putnam, A. P., E. L. Krapp, and R. E. Barrett. Evaluation of National Boiler Inventory. EPA-600/2-75-067 (PB 248 100), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, October 1975. 54 pp.

A report prepared for the EPA by Battelle (7) estimates an industrial pulverized coal capacity of 259 TJ/hr, and fuel consumption of 139 TJ/hr, or a utilization of 60%, assuming 90% boiler efficiency. These estimates are based on extrapolation of NEDS data which assumes that with decreasing source size, NEDS misses a greater percentage of sources. This procedure magnifies the number of small industrial pulverized coal boilers and yields an estimate that approximately 25% of boiler capacity and 85% of boilers on a number basis are below 106 GJ/hr. This conclusion is likewise inconsistent with that of Babcock & Wilcox who state that stokers are more economical in the small size range.

Furthermore, a 1974 Bureau of Mines Mineral Industrial Survey (10) estimates an allotment of 64 x 10^6 metric tons/yr of coal to "Retail Dealers and All Others" (excluding electricity generation, coke plants, and railroad fuel), which corresponds to 191 TJ/hr (using a heating value of 26.1 GJ/metric ton). Battelle's estimated pulverized industrial coal consumption of 139 TJ/hr accounts for nearly all of this coal, and their estimate of industrial stoker firing (198 TJ/hr) by itself exceeds the Bureau of Mines estimate.

Personal communication with the authors of the above references did not resolve the inconsistencies. In order to proceed with this assessment, available information was compiled and a range of possible populations was generated. Derivation of the extremes of the ranges follows. Other populations within the range can be derived by utilizing various combinations of the estimates and assumptions.

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(8) Ehrenfeld, E. R., R. H. Bernstein, K. Carr, J. C. Goldfish, R. G. Orner, and T. Parks. Systematic Study of Air Pollution from Intermediate Size Fossil-Fuel Combustion Equipment, Final Report. APTD 0924 (PB 207 110), U.S. Environmental Protection Agency, Cincinnati, Ohio, July 1971. 241 pp.

(9) Steam/Its Generation and Use, 38th Edition. Babcock & Wilcox, New York, New York, 1972.

(10) Mineral Industry Surveys, Bituminous Coal and Lignite Distribution, Calendar Year 1974. U.S. Department of the Interior, Bureau of Mines, Washington, D.C., April 18, 1975. 53 pp.

Boiler Population--

The number of industrial bituminous pulverized dry bottom boilers is generated based on extrapolation of NEDS data, and ranges from 560 sources to 3,270 sources. A NEDS output of 20 May 1977 (5) listed 440 industrial bituminous pulverized dry bottom boilers. Because NEDS is not complete, fuel consumption data were used to estimate the total number of sources. One reference estimated that 21% of the industrial bituminous coal is consumed in states having no listings in NEDS (1). If it is assumed that NEDS missed 21% of the sources, the total boiler population is 560.

Battelle's estimate of NEDS inadequacies as a function of capacity yielded an estimated 3,847 industrial pulverized coal sources (7). The GCA/Technology Division report assumed that all industrial pulverized coal fired is bituminous (1). Estimates of the split between wet and dry bottom boilers range from 80% to 92% dry. A value of 85% was used to arrive at an upper limit of 3,270 industrial bituminous pulverized dry bottom boilers.

Fuel Consumption--

Fuel consumption estimates range from 686 PJ/yr to 1,815 PJ/yr, with the lower number taken directly from the GCA Technology Division report for industrial bituminous pulverized dry bottom boilers (1). The high estimate is derived from GCA and Battelle input. GCA/Technology Division estimated (based on Battelle and Research Triangle Institute estimates) that coal fired industrial boiler capacity is 750 TJ/hr (see Table 6). Battelle estimated the percentage of this industrial coal fired capacity that is pulverized (7) (see Table 6). Combining both estimates yields an industrial pulverized coal capacity estimate of 454 TJ/hr. Assuming that all industrial pulverized coal fired is bituminous, 85% of it in dry bottom furnaces, as before, yields an industrial pulverized bituminous dry bottom boiler capacity of 380 TJ/hr.

TABLE 6. COAL CAPACITY OF INDUSTRIAL BOILERS (1,7)

Boiler size, GJ/hr	Coal capacity,[a] TJ/hr	Percent pulverized	Pulverized coal capacity, TJ/hr
11 to 21	11	56	306
21 to 53	32		
53 to 106	74		
106 to 211	137		
211 to 528	306		
>528	190	77	148
Total	750		454

[a] Includes boilers capable of burning a secondary fuel.

Efficiency and load estimates from Table 7 were used to obtain fuel consumption (8).

TABLE 7. EFFICIENCY AND LOAD ESTIMATES OF INDUSTRIAL BOILERS (8)

Boiler size, GJ/hr	Efficiency, %	Load, %
<106	77	21
106 to 264	83	35
>264	89	55

The resulting fuel consumption represents the high end of the consumption estimates, or 1,815 PJ/yr.

Average Boiler Size

Because the source population is defined by a range, the average boiler size can also be expressed as a range depending on which population is used. For this study, the average size was determined from the boiler listing in NEDS, and was found to be 222 GJ/hr. The average stack height, based on a report by Paddock and McMann (11), was 45.7 m.

Geographical Distribution

Estimated geographical distributions of industrial dry bottom boilers firing pulverized bituminous coal according to fuel usage and boiler population were obtained from References 1 and 5, respectively. These are shown in Table 8 as a percentage of the total fuel usage and boiler population for this source type on a state-by-state basis. The two listings do not agree completely because the NEDS list does not include all of the smaller boilers, as discussed earlier in this section.

A listing of individual source sites from NEDS is given in Appendix A. Industrial boilers are concentrated in the major industrial states, and they tend to be located in large cities and along major waterways.

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(11) Paddock, R. E., and D. C. McMann. Distributions of Industrial and Commercial-Institutional External Combustion Boilers. EPA-650/2-75-021 (PB 241 195), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, February 1975. 455 pp.

TABLE 8. ESTIMATED GEOGRAPHICAL DISTRIBUTION OF SOURCE TYPE

State	Percent of source population (5)	Percent of fuel consumption (1)	State	Percent of source population (5)	Percent of fuel consumption (1)
Alabama	0.2	4	Nebraska		1
Alaska		1	Nevada		0.2
Arizona		0.2	New Hampshire		<0.1
Arkansas		<0.1	New Jersey		0.1
California		<0.1	New Mexico		<0.1
Colorado		1	New York	6.6	4
Connecticut		<0.1	North Carolina	9.5	2
Delaware		1	North Dakota		1
Florida		1	Ohio	19	15
Georgia	1.4	1	Oklahoma		<0.1
Idaho	1.8	0.5	Oregon	0.7	
Illinois	6.4	7	Pennyslvania	13	9
Indiana	5.0	8	Rhode Island		<0.1
Iowa	5.0	2	South Carolina		2
Kansas	0.2	1	South Dakota		1
Kentucky	1.6	3	Tennessee	5.9	3
Louisiana		<0.1	Texas		0.2
Maine		<0.1	Utah	1.4	1
Maryland	0.9	1	Vermont		<0.1
Massachusetts	0.2	<0.1	Virginia	5.5	4
Michigan	6.6	10	Washington	0.2	0.4
Minnesota	0.5	2	West Virginia	4.3	7
Missouri	1.8	2	Wisconsin	2.0	4
Montana		0.5	Wyoming	0.5	0.4

Note.—Blanks indicate no sources were included in the NEDS file for these states.

STEAM PRODUCTION PROCESS

A simplified process schematic of an industrial dry bottom boiler firing pulveruzed bituminous coal is presented in Figure 4. In general, coal is pulverized, mixed with primary combustion air, and fed to a burner. Secondary combustion air is introduced via the burner, and the resulting mixture is injected into the furnace where it is ignited and burned. Heat generated by combustion is transferred to boiler feedwater through tubes that make up the furnace walls. Steam is removed from the boiler tubes for industrial usage. Heat may be further extracted from the flue gases after they leave the furnace and used to raise the temperature of the steam, boiler feedwater, and/or combustion air. Combustion gases are treated to reduce pollution and then exhausted to the atmosphere.

A more detailed description of the unit operations and equipment involved in steam generation follows, except for emissions/effluent control and ash disposal, which are discussed later in the report. The following description is only an overview because numerous references have been published with the sole purpose of examining combustion and combustion equipment (9, 12-17).

At industrial locations, coal is fed from storage piles or directly from transporting equipment to bunkers that supply the pulverizers. In a pulverizer, coal is reduced in size by impact, attrition, and crushing to the desired degree of fineness. Commonly used grinding mechanisms include ball and race mills, roll and race mills, ball (tube) mills, and impact (hammer) mills.

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(12) Edwards, J. B. Combustion: The Formation and Emission of Trace Species. Ann Arbor Science Publishers, Inc., Ann Arbor, Michigan, 1974. 240 pp.

(13) Combustion-Generated Air Pollution, E. F. Starkman, ed. Plenum Press, New York, New York, 1971. 355 pp.

(14) Field, M. A., D. W. Gill, B. B. Morgan, and P. G. W. Hawksley. Combustion of Pulverized Coal. The British Coal Utilization Research Association, Leatherhead, 1967. 413 pp.

(15) Combustion Engineering, A Reference Book on Fuel Burning and Steam Generation, O. de Lorenzi, ed. Combustion Engineering, Inc., New York, New York, 1957. 1025 pp.

(16) Potter, P. J. Steam Power Plants. The Ronald Press Company, New York, New York, 1949. 503 pp.

(17) Shields, C. D. Boilers - Types, Characteristics, and Functions. FW Dodge Corporation, New York, New York, 1961. 559 pp.

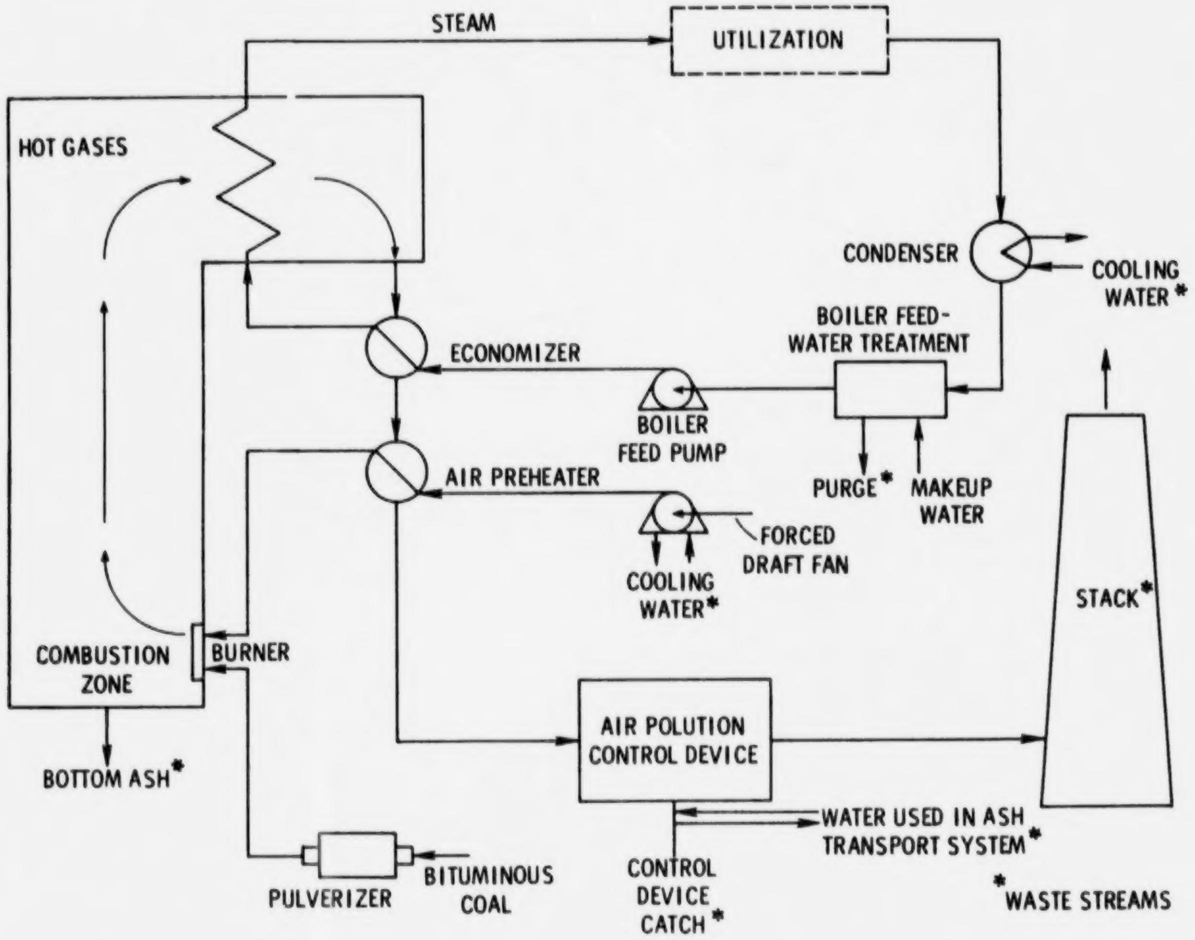
STEAM
UTILIZATION
HOT GASES
CONDENSER
COOLING WATER*
BOILER FEED-WATER TREATMENT
ECONOMIZER
BOILER FEED PUMP
PURGE*
MAKEUP WATER
AIR PREHEATER
FORCED DRAFT FAN
COOLING WATER*
STACK*
COMBUSTION ZONE
BURNER
AIR POLUTION CONTROL DEVICE
BOTTOM ASH*
WATER USED IN ASH TRANSPORT SYSTEM*
PULVERIZER
BITUMINOUS COAL
CONTROL DEVICE CATCH*
*WASTE STREAMS

Figure 4. Simplified process schematic for industrial pulverized bituminous coal-fired boiler.

Pulverizing serves to increase the surface area that can be directly exposed to oxygen thereby increasing the rate of the primary combustion reactions. This results in decreased combustion time, increased throughput of coal, and increased heat output. Coal is pulverized to the extent that 70% will pass a 200-mesh screen. Larger particles may be separated from the coal-air stream by a cyclone and returned to the pulverizer.

During pulverizing, the coal is dried by a stream of hot air that may be either forced or induced through the unit. Air is heated prior to entering the pulverizer by an air heater (boiler waste heat recovery unit) or by an auxiliary heater. The air flow through the pulverizer is additionally reponsible for entraining and thus transporting the crushed coal to a storage vessel (indirect feed) or to the burners (direct feed) where it becomes the primary combustion air. Finely divided coal is explosive in nature; thus, direct feed systems are generally preferred for safety reasons, even though indirect feed systems require less energy.

Pulverizers used in direct feed systems have automatic controls to adjust the coal and air flow rates to compensate for variations in boiler load. Boiler loads from 40% to 60% of capacity can be obtained by adjusting the fuel and air flow rates to the burners. Firing at loads less than 40% requires that burners and possibly pulverizers be taken out of service.

A burner receives the primary air-coal mixture, dilutes it with secondary air, and injects it into the furnace. Burners are designed to promote stability of ignition, completeness of combustion, uniform distribution of temperature and excess air leaving the furnace, and freedom from localized slag deposits. These objectives are partially met through the creation of turbulence and effective adjustment of the ignition point and flame shape. A secondary function of some burners is to fire an alternate fuel concurrently with pulverized coal in order to sustain ignition during start up and periods of low load.

Burners designed to handle pulverized coal are generally classified according to their firing geometry. Figure 5 (18) illustrates the three basic orientations; i.e., vertical, horizontal, and tangential.

Heat released from the combustion of coal is transferred by radiation and convection to the boiler tubes where it is conducted to the boiler feeder.

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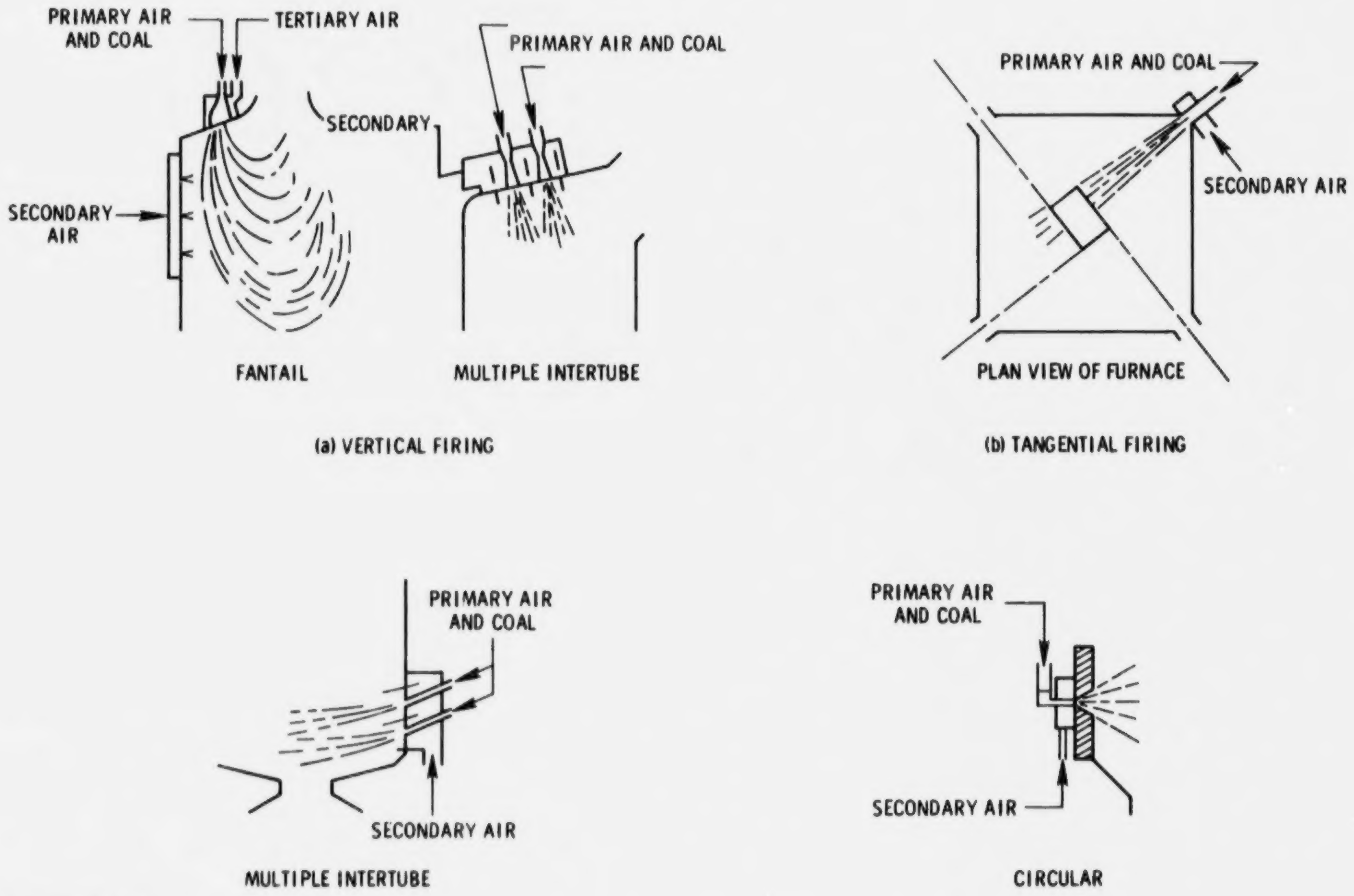
(18) Chemical Engineers' Handbook, Fifth Edition, J. H. Perry and C. H. Chilton, eds. McGraw-Hill Book Company, New York, New York, 1973.


PRIMARY AIR AND COAL
TERTIARY AIR
SECONDARY AIR
FANTAIL
SECONDARY
PRIMARY AIR AND COAL
MULTIPLE INTERTUBE
PRIMARY AIR AND COAL
SECONDARY AIR
PLAN VIEW OF FURNACE
PRIMARY AIR AND COAL
SECONDARY AIR
MULTIPLE INTERTUBE
PRIMARY AIR AND COAL
SECONDARY AIR
CIRCULAR

(a) VERTICAL FIRING

(b) TANGENTIAL FIRING

(c) HORIZONTAL FIRING

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Figure 5. Various methods of firing pulverized bituminous coal (18).

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Boiler feedwater is composed of recycled condensed steam and makeup water. Makeup water must be treated prior to use to remove suspended and dissolved solids. A characterization of typical makeup water is presented in Table 9 (19). Concentrations of the listed species in boiler water can result in reduced efficiency and eventually in boiler tube failure. Specific problems caused by these materials are summarized in Table 10 (20).

TABLE 9. TYPICAL CHARACTERISTICS OF BOILER WATER SUPPLIES (19)

Constituent	Concentration, g/m^3
Calcium, as $CaCO_3$	40 to 200
Magnesium, as $CaCO_3$	10 to 50
Alkalinity, as $CaCO_3$	5 to 50
Sulfate, as SO_4	20 to 140
Chloride, as Cl	10 to 150
Silica, as SiO_2	2 to 15
Iron, as Fe	0.2 to 2.0
Manganese, as Mn	0.1 to 1.0
Oil	<1 to 5.0
Suspended solids	10 to 200
pH	5.5 to 7.5

The level of treatment needed to alleviate these problems is a function of both the feedwater composition and the quality of the steam generated (higher temperature, higher pressure steam requires more treatment). Although some high pressure industrial boilers have severe feedwater quality requirements similar to those for electric utilities, most industrial boilers operate at pressures below 4 MPa, and the raw water is usually only treated

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(19) Nichols, C. R. Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category. EPA-440/1-74-029-A (PB 240 853), U.S. Environmental Protection Agency, Washington, D.C., October 1974. 865 pp.

(20) Betz Handbook of Industrial Water Conditioning. Betz Laboratories, Inc., Trevose, Pennsylvania, 1976. pp. 18-19.

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TABLE 10. WATER IMPURITIES, PROBLEMS, AND TREATMENT (20)

Reprinted from Betz Handbook of Industrial Water Conditioning, pp 18-19, by permission of Betz Laboratories, Inc., Trevose, Pennsylvania.

Constituent	Difficulties caused	Means of treatment
Turbidity	Deposits in water lines, process equipment, boilers, etc.	Coagulation, settling and filtration.
Color	May cause foaming in boilers. Hinders precipitation methods such as iron removal and softening.	Coagulation and filtration. Chlorination. Adsorption by activated carbon.
Hardness	Chief source of scale in heat exchange equipment, boilers, pipe lines, etc.	Softening. Demineralization. Internal boiler water treatment. Surface active agents.
Alkalinity	Foaming and carryover of solids with steam. Embrittlement of boiler steel. Bicarbonate and carbonate produce CO_2 in steam, a source of corrosion in condensate lines.	Lime and lime-soda softening. Acid treatment. Hydrogen zeolite softening. Demineralization. Dealkalization by anion exchange.
Free mineral acid	Corrosion.	Neutralization with alkalies.
Carbon dioxide	Corrosion in water lines and particularly steam and condensate lines.	Aeration. Deaeration. Neutralization with alkalies.
pH	pH varies according to acidic or alkaline solids in water. Most natural waters have a pH of 6-8.	pH can be increased by alkalies and decreased by acids.
Sulfate	Adds to solids content of water, but, in itself, is not usually significant. Combines with calcium to form calcium sulfate scale.	Demineralization.
Chloride	Adds to solids content and increases corrosive character of water.	Demineralization.
Nitrate	Adds to solids content, but is not usually significant industrially. Useful for control of boiler metal embrittlement.	Demineralization.

(continued)

TABLE 10 (continued)

Constituent	Difficulties caused	Means of treatment
Silica	Scale in boilers and cooling water systems. Insoluble turbine blade deposits due to silica vaporization.	Hot process removal with magnesium salts. Adsorption by highly basic anion exchange resins, in conjunction with demineralization.
Iron	Source of deposits in water lines, boilers, etc.	Aeration. Coagulation and filtration. Lime softening. Cation exchange. Contact filtration. Surface active agents for iron retention.
Manganese	Same as iron.	Same as iron.
Oxygen	Corrosion of water lines, heat exchange equipment, boilers, return lines, etc.	Deaeration. Sodium sulfite. Corrosion inhibitors.
Hydrogen sulfide	Corrosion.	Aeration. Chlorination. Highly basic anion exchange.
Ammonia	Corrosion of copper and zinc alloys by formation of complex soluble ion.	Cation exchange with hydrogen zealite. Chlorination. Deaeration.
Dissolved solids	Dissolved solids is measure of total amount of dissolved matter, determined by evaporation. High concentrations of dissolved solids are objectionable because of process interference and as a cause of foaming in boilers.	Various softening processes, such as lime softening and cation exchange by hydrogen zeolite, will reduce dissolved solids. Demineralization.
Suspended solids	Suspended solids is the measure of undissolved matter, determined gravimetrically. Suspended solids plug lines, cause deposits in heat exhcange equipment, boilers, etc.	Subsidence. Filtration, usually preceded by coagulation and settling.
Total solids	Total solids is the sum of dissolved and suspended solids, determined gravimetrically.	See "Dissolved Solids" and "Suspended Solids."

to remove hardness, insoluble residues, excess silica, and alkalinity (17). Detailed descriptions of water treatment technology are readily available in the literature (15, 20, 21, 22).

As water is converted to steam in the boiler, trace impurities still present, such as dissolved solids, are concentrated in the boiler water. When sufficiently high concentrations are reached, these materials precipitate and coat the inner sides of the heat transfer surfaces. This impairs the transfer of heat in the boiler unit and reduces boiler efficiency. In order to prevent deposition of these materials, a portion of the boiler water is usually drawn off and replaced by feedwater. The blowdown (that portion of the boiler water removed to maintain an acceptable dissolved solids concentration) then becomes a wastewater stream.

Steam is generated primarily in the waterwalls of the furnace for boilers in this source type. These waterwalls consist of vertical tubes on all walls of the furnace where feedwater is heated and vaporized. In typical coal-fired industrial boilers, approximately 50% of heat adsorption takes place in these tubes (15). The product leaving the waterwalls is saturated steam with entrained water droplets. The water is removed and recycled while dry saturated steam proceeeds to utilization or to additional heating when appropriate.

Steam generated in industrial dry bottom boilers firing pulverized bituminous coal may be used to generate electricity, to supply process heat, as a power source for industrial equipment, and in space heating of factories or other industrial buildings. A percentage breakdown of actual consumption is not available. The quantity of steam recycled versus that used only once is also unknown.

Plants that recycle steam may condense and/or cool it in recirculating or once-through cooling equipment. If the steam is used for process or space heating, it may condense in the system and be returned directed to the boiler. Current practices related specifically to this source type, e.g., the percentage of plants using cooling equipment and the proportion of recirculating versus once-through cooling systems, are not adequately characterized in the literature.

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(21) Industrial Water Treatment Practice, P. Hamer, J. Jackson, and E. F. Thurston, eds. Butterworth and Company Ltd., London, England, 1961. 514 pp.

(22) Nordell, E. Water Treatment for Industrial and Other Uses, Second Edition. Reinhold Publishing Corp., New York, New York, 1961. 598 pp.

As mentioned earlier, additional heat may be recovered from combustion gases before they are discharged. This waste heat recovery is accomplished in economizers and air heaters, which use the low grade heat to increase boiler efficiency. Economizers heat the feedwater and thereby reduce the amount of energy required to generate steam in the boiler. Air heaters preheat the combustion air, which increases boiler efficiency by improving combustion conditions.

If high pressure, high temperature steam is required for the operation of a turbine (not typical for industrial size units), additional heat can be extracted by steam superheaters and reheaters, which are banks of heat transfer tubes located near the furnace outlet. The use of superheaters and reheaters does not affect the overall efficiency of the boiler.

COMBUSTION PROCESS

In the basic combustion process, carbon and hydrogen in coal react with oxygen to form carbon dioxide and water. However, because of the complex nature of coal and the many other reactions occurring under actual combistion conditions in a boiler, a wide assortment of other emission species are produced. Some materials (e.g., sulfur oxides) are formed from other constituents in the coal; others (e.g., carbon monoxide) are products of incomplete combustion reactions. This section characterizes the bituminous coal consumed by this source type and describes the combustion process.

Coal Characterization

The American Society for Testing and Materials (ASTM) has classified coals into the 4 classes and 13 groups shown in Table 11 (2). Each class and group is defined by a range of fixed carbon, volatile matter, and calorific value. For this program, bituminous coal is assumed to include all bituminous and subbituminous coal types.

Based on distribution of bituminous and lignite coal to retail dealers and all others (excluding that consumed by electric utilities and by coke and gas plants, that used as railroad fuel, and that sold to mines or mine employes), 67% of bituminous coal for industrial pulverized dry bottom boilers originates in the Appalachian region (23). The Appalachian region consists of coal producing districts 1 to 8 and 13 as defined by the Bituminous

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(23) Minerals Yearbook 1974, Volume I: Metals, Minerals, and Fuels. U.S. Department of the Interior, Bureau of Mines, Washington, D.C., 1976. p. 395.

TABLE 11. CLASSIFICATION OF COALS BY RANK (2)[a]

Reprinted from 1976 Annual Book of ASTM Standards, p. 213,
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	Fixed carbon limits, % (dry, mineral-matter-free basis)		Volatile matter limits, % (dry, mineral-matter-free basis)		Calorific value limits, Btu per pound (moist,[b] mineral-matter-free basis)	
Coal rank	Equal or greater than	Less than	Greater than	Equal or less than	Equal or greater than	Less than
Anthracitic:						
Meta-anthracite	98			2		
Anthracite	92	98	2	8		
Semianthricite[c]	86	92	8	14		
Bituminous:						
Low volatile bituminous coal	78	86	14	22		
Medium volatile bituminous coal	69	78	22	31		
High volatile A bituminous coal		69	31		14,000[d]	
High volatile B bituminous coal					13,000[d]	14,000
High volatile C bituminous coal					{11,500 10,500	13,000 11,500
Subbituminous:						
Subbituminous A coal					10,500	11,500
Subbituminous B coal					9,500	10,500
Subbituminous C coal					8,300	9,500
Lignite:						
Lignite A					6,300	8,300
Lignite B						6,300

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[a] This classification does not include a few coals, principally nonbanded varieties, which have unusual physical and chemical properties and which come within the limits of fixed carbon or calorific value of the high-volatile bituminous and subbituminous ranks. All of these coals either contain less than 48 percent dry, mineral-matter-free fixed carbon or have more than 15,500 moist, mineral-matter-free British thermal units per pound.

[b] Moist refers to coal containing its natural inherent moisture but not including visible water on the surface of the coal.

[c] If agglomerating, classify in low-volatile group of the bituminous class.

[d] Coals having 69 percent or more fixed carbon on the dry, mineral-matter-free basis shall be classified according to fixed carbon, regardless of calorific value.

Coal Act of 1937. Table 12 presents a characterization of Appalachian bituminous coal from the literature (24-27). Although average concentrations are given for elemental composition, levels can vary significantly from state to state, mine to mine, and even within the thickness of a coal seam. The concentration of a particular element in coal can range over two orders of magnitude (24-27).

Pulverized Coal Combustion

Coal burns in a diffusion flame because the solid nature of the fuel prohibits mixing of the fuel and oxidant on a molecular scale. Processes involved in the combustion of a solid fuel are shown in Figure 6 (12). With the addition of radiant energy from an ignition device or the combustion zone, volatile components are vaporized and flow away from the solid surface, and the solid portion of the fuel begins to pyrolyze. At this point, no oxidation of the fuel at the surface occurs due to lack of intimate contact with the oxidant. A diffusion flame is established where the mixing of combustibles and oxidant forms a combustible mixture. This is noted as the primary combustion zone in Figure 6. Additional transfer of heat results in additional vaporization of volatiles, pyrolysis, and a rise in surface temperature of the solid to the incandescent range.

Radiant energy from incandescence promotes additional pyrolysis of the vapors. After the depletion of volatiles, oxidation of the solid commences. Oxygen diffuses to the solid surface and oxidation of the nonvolatiles occurs, resulting in the release of more heat. Carbon monoxide and dioxide, water, hydrogen, nitrogen oxides, sulfur oxides, particles from noncombusted vapors, and impurities may form or begin to form in the combustion zone.

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(24) Swanson, V. E., J. H. Medlin, J. R. Hatch, S. L. Coleman, G. H. Wood, S. D. Woodruff, and R. T. Hildebrand. Collection, Chemical Analysis, and Evaluation of Coal Samples in 1975. Open-File Report 76-468, U.S. Department of the Interior, Denver, Colorado, 1976. 503 pp.

(25) Ruch, R. R., H. J. Gluskoter, and N. F. Shimp. Occurrence and Distribution of Potentially Volatile Trace Elements in Coal. EPA-650/2-74-054 (PB 238 091), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, July 1974. 96 pp.

(26) Kessler, R., A. G. Sharkey, Jr., and R. A. Friedel. Analysis of Trace Elements in Coal by Spark-Source Mass Spectrometry. Report of Investigations 7714, U.S. Department of the Interior, Pittsburgh, Pennsylvania, 1973. 8 pp.

(27) Magee, E. M., H. J. Hall, and G. M. Varga, Jr. Potential Pollutants in Fossil Fuels. EPA-R2-73-249 (PB 225 039), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, June 1973. 223 pp.

TABLE 12. ARITHMETIC MEAN OF PROXIMATE AND ULTIMATE ANALYSES AND ELEMENTAL COMPOSITION FOR APPALACHIAN COAL REGION SAMPLES

Constituent	Arithmetic mean	Number of samples	Reference
Moisture, %	2.8	158	24
Volatile matter, %	31.6	158	24
Fixed carbon, %	54.6	158	24
Ash, %	11.0	158	24
Hydrogen, %	4.9	158	24
Carbon, %	72.6	158	24
Nitrogen, %	1.3	158	24
Oxygen, %	7.8	158	24
Sulfur, %	2.3	158	24
Heating value, J/kg	30×10^6	158	24
Elements, ppm:			
Aluminum	1.8×10^4	350	24-26
Arsenic	2.6×10^1	350	24-26
Antimony	1.2	350	24-26
Barium	1.0×10^2	341	24,26
Beryllium	2.1	426	24-27
Bismuth	$<1.0 \times 10^{-1}$	10	25
Boron	2.9×10^1	413	24-27
Bromine	1.1×10^1	19	24,25
Cadmium	6.8×10^{-1}	350	24-26
Calcium	1.3×10^3	350	24-26
Cerium	1.4×10^1	10	25
Cesium	2.5×10^1	10	25
Chlorine	7.3×10^2	19	24,25
Chromium	2.0×10^1	426	24-27
Cobalt	6.8	426	24-27
Copper	2.2×10^1	426	24-27
Dysprosium	1.4	10	25
Erbium	2.6×10^{-1}	10	25
Europium	5.9×10^{-1}	10	25
Fluorine	7.8×10^1	350	24-26
Gadolinium	1.0	10	25
Gallium	6.5	426	24-27
Germanium	4.8	95	24,25,27
Gold	4.0×10^{-1}	10	25
Hafnium	1.2	10	25
Holmium	2.1×10^{-1}	10	25
Iodine	1.1	10	25
Iridium	$<2.0 \times 10^{-1}$	10	25
Iron	1.9×10^4	350	24-26
Lanthanium	9.3	350	24-26
Lead	1.5×10^1	350	24-26
Elements (continued):			
Lithium	2.7×10^1	341	24,26
Lutenium	1.2×10^1	10	25
Magnesium	6.9×10^2	350	24-26
Manganese	5.9×10^2	350	24-26
Mercury	1.4×10^{-1}	350	24-26
Molybdenum	3.1	426	24-27
Neodymium	1.2×10^3	10	25
Nickel	1.5×10^1	426	24-27
Niobium	5.4	341	24,26
Osmium	$<2.0 \times 10^{-1}$	10	25
Palladium	$<1.0 \times 10^{-1}$	10	25
Phosphorus	9.2×10^{-1}	19	24,25
Platinum	$<3.0 \times 10^{-1}$	10	25
Potassium	2.3×10^3	350	24-26
Praseodymium	2.1	10	25
Rhenium	$<2.0 \times 10^{-1}$	10	25
Rhodium	$<1.0 \times 10^{-1}$	10	25
Rubidium	3.7×10^1	10	25
Ruthenium	4.0×10^{-1}	10	25
Samarium	1.9	10	25
Scandium	5.1	341	24,26
Selenium	4.5	350	24-26
Silicon	2.7×10^4	350	24-26
Silver	2.5×10^{-2}	10	25
Sodium	3.3×10^2	350	24-26
Strontium	1.0×10^2	341	24,26
Tantalum	9.5×10^{-1}	10	25
Tellurium	3.4×10^{-1}	10	25
Terbium	3.2×10^{-1}	10	25
Thallium	1.0×10^{-1}	10	25
Thorium	4.8	341	24,26
Thulium	$<1.0 \times 10^{-1}$	10	25
Tin	2.4	95	24,25,27
Titanium	8.1×10^2	415	24-27
Tungsten	2.8×10^{-1}	10	25
Uranium	1.4	341	24,26
Vanadium	2.0×10^1	426	24-27
Ytterbium	9.8×10^{-1}	341	24,26
Yttrium	1.1×10^1	426	24-27
Zinc	1.8×10^1	426	24-27
Zirconium	5.0×10^1	350	24-26

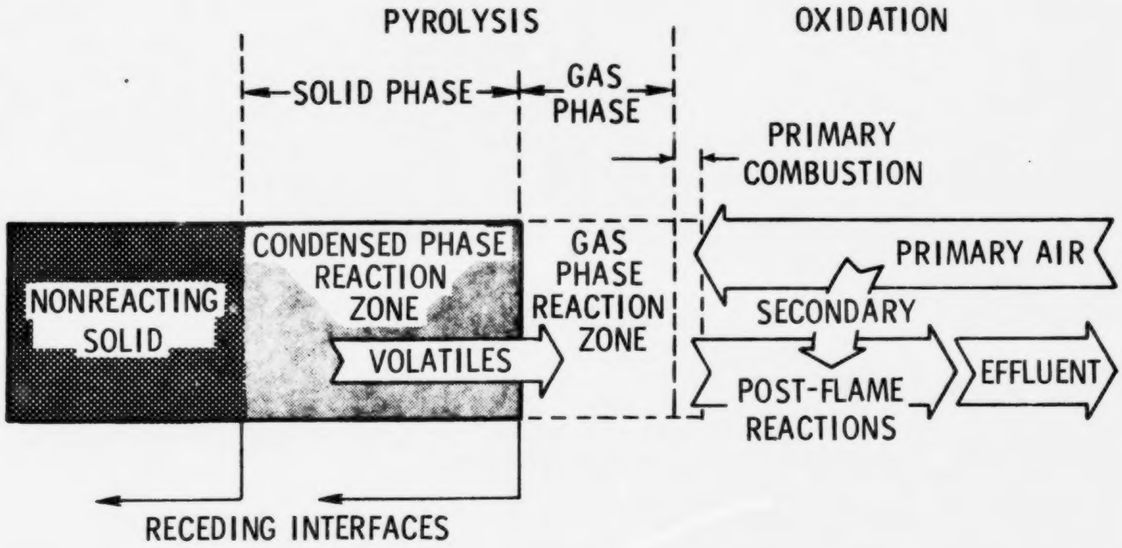
PYROLYSIS
OXIDATION
SOLID PHASE
GAS PHASE
PRIMARY COMBUSTION
NONREACTING SOLID
CONDENSED PHASE REACTION ZONE
VOLATILES
GAS PHASE REACTION ZONE
PRIMARY AIR
SECONDARY
POST-FLAME REACTIONS
EFFLUENT
RECEDING INTERFACES

Figure 6. Combustion of a solid (12).

Reprinted from the Formation and Emission of Trace Species by J. B. Edwards, p. 151, by permission of Ann Arbor Science Publishers, Inc.

Directly downstream of the combustion zone is the postflame region. This region may be luminous, and therefore it is often considered as part of the flame itself. Many chemical and physical processes may occur in the postflame region because the reactants may be both gaseous and solid. Radical recombination (chain termination) reactions such as the recombination of atomic oxygen and the formation of water from atomic hydrogen and the hydroxyl radical occur as the combustion gases cool. Reaction of fuel components and their combustion products with other hydrocarbons, dehydrogenation of hydrocarbons to species of greater unsaturation, and the cracking of hydrocarbons are among the pyrolytic postflame reactions.

SECTION 4

AIR EMISSIONS AND CONTROL TECHNOLOGY

SOURCE AND NATURE OF AIR EMISSIONS

Air emissions emanating from this source originate primarily from the combustion of pulverized bituminous coal in the boiler furnace. Other potential air emission sources are coal and ash handling and cooling towers when present.

Airborne emissions resulting from coal combustion include particulate matter, sulfur oxides, nitrogen oxides, carbon monoxide, hydrocarbons, polycyclic organic materials, and most elements. Mass emissions of particulate matter, sulfur oxides, and the elements found in combustion product gases as either particulate matter or vapors are directly related to the ash, sulfur, and individual elemental concentrations in the fuel. Nitrogen oxides arise from nitrogen compounds in coal and the nitrogen component of the combustion air. Carbon monoxide, hydrocarbons, and polycyclic organics are all products of incomplete combustion.

During combustion in a coal-fired furnace the inorganic constituents (ash) of the coal are entrained in the effluent gas stream (fly ash) or removed as bottom ash. In a dry bottom furnace 60% to 90% (averaging 80% to 85%) of these noncombustible materials are entrained in the effluent gas stream (18, 28) and, unless collected in a control device, are emitted to the atmosphere. The remaining portion collects in the furnace and is periodically removed as bottom ash. The ash content of most bituminous coals ranges from 4% to 15% and averages about 11% (29).

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(28) Cuffe, S. T., and R. W. Gerstle. Emissions from Coal-Fired Power Plants: A Comprehensive Summary. Public Health Service Publication 999-AP-35 (PB 174 708), U.S. Department of Health, Education, and Welfare, Cincinnati, Ohio, 1967. 26 pp.

(29) Smith, W. S., and C. W. Gruber. Atmospheric Emissions from Coal Combustion - An Inventory Guide. Public Health Service Publication 999-AP-24 (PB 170 851), U.S. Department of Health, Education, and Welfare, Cincinnati, Ohio, April 1966. 112 pp.

There are several mechanisms by which particulate matter, including aerosol mists, is formed during the combustion process and the subsequent flow of combustion products through the flue gas system. The inorganic species that are not volatile at combustion temperatures coalesce in the combustion zone to form a heterogeneous melt in which a small portion of the volatile inorganic and combustible materials are trapped. This material becomes the bottom ash and the bulk of the fly ash. As the combustion gases move away from the furnace and cool, the volatile inorganic species and any high molecular weight organics which escaped combustion condense either onto the particles present in the gas stream or through self-nucleation. This process is essentially complete by the time the gases reach the electrostatic precipitator (ESP), the driving force being a 1,000°C plus temperature drop over 6 seconds or less which results in supersaturated conditions. Some additional material is added to the particles through adsorption of gaseous materials such as chlorine, bromine, fluorine, and mercury, and by gas phase reactions in the flue gas that produce additional condensable materials. Sulfuric acid mists are produced in the latter manner by the fly ash catalyzed conversion of sulfur dioxide to sulfur trioxide and the rise in flue gas dew point caused by the presence of sulfur (30).

Fly ash generally occurs as fine spherical particles. A typical coal ash particle size distribution has a bimodal distribution, with peaks in the regions of 0.07 μm and 0.6 μm for particle size diameter (31). Chemical and physical descriptions of pulverized coal ash are found in Section 6.

Concentrations of trace elements emitted as either particles or vapors are closely related to the elemental composition of the coal. However, the concentrations found in fly ash are affected by the partitioning of elements between the fly ash and bottom ash. Concentrations of elements found in fly ash emitted after passing through particulate controls are further influenced by a mechanism known as particulate enrichment.

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(30) Hillenbrand, L. J., R. B. Engdahl, and R. E. Barrett. Chemical Composition of Particulate Air Pollutants from Fossil-Fuel Combustion Sources. EPA-R2-73-216 (PB 219 009), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, March 1973.

(31) Ragaini, R. C., and J. M. Ondov. Trace-Element Emissions from Western U.S. Coal-Fired Power Plants. Journal of Radioanalytical Chemistry, 37:670-691, 1977.

Three distinct classes of elements have been identified according to their partitioning behavior (32-34). First are the elements that show no preference for bottom or fly ash. These elements are not volatilized in the combustion zone but form a melt of heterogeneous composition that becomes both bottom and fly ash. The second class consists of elements that partially volatilize in the combustion zone and condense onto fly ash particles in the flue gas as it cools. Elements belonging to this group are thus preferentially depleted from the bottom ash and concentrated in the fly ash. The third class is made up of elements that are volatiltilized and essentially remain in the vapor state. These elements are thus emitted directly to the atmosphere as gases; their mass emission rate is directly proportional to their concentration in the coal and is independent of any particulate control device. It should also be noted that a number of elements do not fit well into any of the above clases but exhibit behavior intermediate between Classes I and II. The elements belonging to each class are listed in Table 13 (32-34).

TABLE 13. CLASSIFICATION OF ELEMENTS ACCORDING TO THEIR PARTITIONING BEHAVIOR (32-34)

Partitioning class	Elements
Class I - Elements equally distri- between bottom and fly ash	Aluminum, barium, bismuth, calcium, cerium, cobalt, europium, hafnium, iron, lanthanum, magnesium, manganese, niobium, potassium, rubidium, samarium, scandium, silicon, strontium, tantalum, thorium, tin, titanium, yttrium, zirconium
Class II - Elements concentrating in fly ash	Antimony, arsenic, cadmium, copper, gallium, lead, molybdenum, polonium, selenium, thallium, zinc
Class III - Elements remaining in gas phase	Bromine, chlorine, fluorine, mercury
Elements intermediate between Classes I and II	Cesium, chromium, nickel, sodium, uranium, vanadium

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(32) Davison, R. L., D. F. S. Natusch, J. R. Wallace, and C. A. Evans, Jr. Trace Elements in Fly Ash - Dependence of Concentration on Particle Size. Environmental Science and Technology, 8(13):1107-1113, 1974.

(33) Kaakinen, J. W., R. M. Jorden, M. H. Lawasani, and R. E. West. Trace Element Behavior in Coal-Fired Power Plant. Environmental Science and Technology, 9(9):862-869, 1975.

(34) Klein, D. H., A. W. Andren, J. A. Carter, J. F. Emery, C. Feldman, W. Fulkerson, W. S. Lyon, J. C. Ogle, Y. Talmi, R. I. VanHook, and N. Bolton. Pathways of Thirty-Seven Trace Elements Through Coal-Fired Power Plant. Environmental Science and Technology, 9(10):973-979, 1975.

Particulate enrichment is a result of the volatilization and subsequent condensation of the Class II elements mentioned above. Because smaller fly ash particles present a larger surface area per unit mass for condensation, they are the ones on which the class II elements are preferentially concentrated. This is of particular interest because the smaller particles are harder to remove from the flue gas and therefore make up a high percentage of the ash emitted after controls.

Sulfur oxide (SO_x) emissions result from the oxidation of the pyritic and organic sulfur found in coal. Since no more than a small percentage of the sulfur is converted to particulate sulfates (35), the emission rate is almost totally dependent on the fuel sulfur content and the fuel feed rate to the boiler. Thus, SO_x emissions can be closely approximated by the following equation (36):

$$SO_x = 2(R)(S) \tag{1}$$

where SO_x = emission rate of sulfur oxides, kg/hr
2 = stoichiometric ratio of SO_2 (the primary SO_x specie) to S
R = fuel flow rate, kg/hr
S = fraction of sulfur in the coal

In the combustion zone the fuel sulfur is rapidly converted to SO_2 and SO_3 although the concentration of the SO_3 formed initially is only about 0.5% of the SO_2 concentration. As the sulfur dioxide cools while traveling through the flue gas ducts it is slowly oxidized to SO_3 by homogeneous gas phase reactions and by catalytic oxidation in the presence of iron oxide, vanadium pentoxide, and other metal oxides in the fly ash and ash deposits on the heat transfer surfaces (37-39). Because these reactions are slow, equilibrium SO_2-SO_3 concentrations are not reached in the final exhaust gas. The initial SO_3 concentration is relatively independent of excess air at levels above 5% excess air. However, reducing excess air to a few tenths of 1% causes SO_3 concentrations to fall to nearly zero (40). The SO_3 formed may react with moisture in the flue gas to produce sulfuric acid if stack temperatures drop below the acid dew point.

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(35) Orning, A. A., C. H. Schwartz, and J. F. Smith. Minor Products of Combustion in Large Coal-Fired Steam Generators. ASME Paper No. 64-WA/FU-2, presented at the 1964 Winter Annual Meeting of the American Society of Mechanical Engineers, New York, New York, November 29 - December 4, 1964. 12 pp.

(36) McKnight, J. S. Effects of Transient Operating Conditions on Steam-Electric Generator emissions. EPA-600/2-75-022 (PB 247 701), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, August 1975. 114 pp.

(37) Corn, M., and R. T. Cheng. Interactions of Sulfur Dioxide with Insoluble Suspended Particulate Matter. Journal of the Air Pollution Control Association, 22(11):870-875, 1972.

(continued)

The nature of nitrogen oxide emissions is somewhat more complex than that of sulfur oxides because both the fuel and the combustion air are sources of nitrogen in the combustion zone. Combustion air is about 79% nitrogen, and coal contains from 0.5% to 2% nitrogen by weight in the form of pyrroles, pyridines, quinolines, carbazoles, and amines (41). Nitrogen oxide emissions usually represent less than 0.1% of the nitrogen entering the furnace (36), indicating that very little atmospheric nitrogen is converted to NO_x in the furnace. This is partially because the conversion of atmospheric nitrogen to nitrogen oxides (thermal NO_x formation) is highly temperature dependent and proceeds slowly at the relatively low flame temperatures (<1,530°C) encountered in a typical fuel-lean coal flame. On the other hand, fuel nitrogen conversion is readily accomplished at lower temperatures and contributes from 60% to 100% (averaging about 80%) of the nitrogen oxides formed at 730°C to 1,530°C. This is because the bond energies in coal are typically 80 kcal/mole to 100 kcal/mole compared to the 225 kcal/mole required for thermal nitrogen oxide formation (41). The amount of fuel nitrogen oxidized depends

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(continued)

(38) Vogel, R. F., B. R. Mitchell, andF. e. Massoth, Reactivity of SO_2 with Supported Metal Oxide-Alumina Sorbents. Environmental Science and Technology, 8(5):432-436, 1974.

(39) Wilson, J. S. and M. W. Redifer. Equilibrium Composition of Simulated Coal Combustion Products: Relationship to Fireside Corrosion and Ash Fouling. Journal of Engineering for Power. Transactions of the ASME, 96(A-2):145-152, 1974.

(40) Barrett, R. E., J. D. Hummell, and W. T. Reid. Formation of SO_3 in a Noncatalytic Combustor. Journal of Engineering for Power, Transactions of the ASME, 88(4):165-172, 1966.

(41) Vogt, R. A., and N. M. Laurendeau. Nitric Oxide Formation in Pulverized Coal Flames. PURDU-CL-76-08 (PB 263 277), National Science Foundation, Washington, D.C., September 1976.

on the excess air present; for low excess air levels (<5%) it is generally between 20% and 50% (42-45).

Nitrogen oxides are formed in the combustion zone, the primary constituent (approximately 95% of total NO_x) being nitric oxide (NO). The NO concentration attained depends on the flame temperature and the residence time in the furnace as NO dedeomposition reactions are rapidly quenched by the lower temperature at the furnace outlet. Further oxidation of NO continues with time but at a very slow pace compared to that for the time spent in the boiler system. Therefore, the concentrations of nitrogen oxides reached in the furnace remain relatively unchanged at the point of discharge. Other oxides of nitrogen include nitrogen dioxide (NO_2), which accounts for about 5% of the total NO_x, and trace amounts of nitrogen pentoxide (N_2O_5) and nitrous oxide (N_2O) (39, 46).

Incomplete combustion is responsible for the formation of carbon monoxide and hydrocarbons, including polycyclic organic materials (POM). Thus, the coal combustion efficiency is the controlling factor in the production and emissions of these pollutants. Conditions necessary for the conversion of hydrocarbon fuels to carbon dioxide and water are sufficient time for the completion of the chemical reactions, sufficient temperature to heat the

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(42) Song, Y. H., J. M. Beer, and A. F. Sarofim. Fate of Fuel Nitrogen during Pyrolysis and Oxidation. In: Proceedings of the Second Stationary Source Combustion Symposium, Volume IV. Fundamental Combustion Research. EPA-600/7-77-073d (PB 274 029), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, July 1977. pp. 79-100.

(43) Axworthy, A. E., G. R. Schneider, M. D. Shuman, and V. H. Dayan. Chemistry of Fuel Nitrogen Conversion to Nitrogen Oxides in Combustion. EPA-600/2-76-039 (PB 250 373), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, February 1976. 365 pp.

(44) Sterling, C. V., and J.O.L. Wendt. Kinetic Mechanisms Governing the Fate of Chemically Bound Sulfur and Nitrogen in Combustion. EPA-650/2-74-017 (PB 230 895), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, August 1972. 144 pp.

(45) Pershing, D. W., G. B. Martin, and E. E. Berkau. Influence of Design Variables on the Production of Thermal and Fuel NO from Residual Oil and Coal Combustion. In: Air - II. Control of NO_x and SO_x Emissions, AIChE Symposium Series No. 148:71:19-29, 1975.

(46) Environmental Control Technology, TID-26758-P7, U.S. Atomic Energy Commission, Washington, D.C., November 11, 1974.

fuel through its decomposition stages and to ignite it, and sufficient turbulence to thoroughly mix the fuel and oxygen. In a furnace firing pulverized coal the major limiting factor is the ability of the burner to provide sufficient turbulence in the very short time allowed for combustion.

Carbon monoxide (CO) formation is directly related to the fuel-air ratio. Fuel rich conditions stimulate CO formation with maximum CO concentrations occurring at minimum oxygen concentrations. CO emissions are generally low (<1 ppm) for dry bottom boilers (47, 48).

Like CO, hydrocarbon emissions are dependent on the fuel-air ratio, and they appear in small concentrations even though excess oxygen is available in the furnace. Either incomplete mixing or variations of reactant concentrations in time permit isolated oxygen-deficient volumes of gas to escape combustion.

Polycyclic organic materials result from the combination of free radical species formed in the flame. The synthesis of these molecules is dependent on many combustion variables, including the presence of a chemically reducing atmosphere. Under this condition, radical chain propagation is enhanced, allowing the buildup of a complex POM molecule. A list of POM species encountered during sampling is presented later in Table 17. Because POM compounds melt/sublime at about 200°C, which is approximately 50°C higher than most stack temperatures (47), they should be in the condensed phase when emitted.

Emissions from industrial boilers caused by coal and ash handling and by evaporation and aerosol formation in cooling towers do not approach the magnitude of the combustion-related emissions. In fact, the sum of the mass emissions from these sources totals less than 1% of the combustion mass emissions.

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(47) Cato, G. A. Field Testing: Trace Element and Organic Emissions from Industrial Boilers. EPA-600/2-76-086b (PB 261 263), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, October 1976. 156 pp.

(48) Bartz, D. R., and S. C. Hunter. Field Testing: Application of Combustion Modifications to Control Pollutant Emissions from Industrial Boilers, Phase II. In: Proceedings of the Second Stationary Source Combustion Symposium; Volume I: Small Industrial, Commercial, and Residential Systems. EPA-600/7-77-073a (PB 270 923), U.S. Environmental Protection Agency Research Triangle Park, North Carolina, July 1977. pp. 207-245.

Emissions resulting from the handling of coal include particulate emissions of coal dust from wind entrainment, and gaeous emissions of carbon monoxide, methane, and other highly volatile hydrocarbons. These emissions arise primarily from coal storage piles. Ash handling emissions result from wind entrainment of exposed ash particles during ash conveying, transport, and disposal. Emissions from coal storage piles have been previously assessed (4), and emissions from ash handling are discussed in Section 6.

Cooling tower emissions are divided into two categories, fog and drift, with 20 μm particle size as the dividing point. Fog (<20 μm) results from condensation and consists of relatively pure water. Drift droplets have the composition of the cooling liquor, which has a total dissolved solids content on the order of 1,000 ppm, consisting mainly of calcium sulfate ($CaSO_4$) (49). Drift deposition is controlled by many atmospheric variables, but typically, approximately 70% deposits within about 122 m (1).

EMISSIONS DATA

There are limited data in the literature characterizing airborne emissions from industrial dry bottom boilers burning pulverized bituminous coal. Most emissions data in the literature do not attach all of the descriptors used to define this category when identifying the source of the sampling data. Commonly, a source is identified only as a coal-fired industrial boiler, or by size rather than application, and in order to use the data it was necessary to assume that the coal used was bituminous, or that the industrial boiler was dry bottom. This is a reasonable assumption because dry bottom boilers firing pulverized bituminous coal are the most common (47%) unit in this general category of coal-fired industrial boilers (1). Moreover, pulverized boilers predominate in the larger boilers that are generally tested.

Emissions data were compiled from actual test data, calculated based on material balance considerations using literature resources, and generated from a sampling program that measured the emissions from a typical boiler in this source category.

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(49) Carson, J. E. Atmospheric Impacts of Evaporative Cooling Systems. ANL/ES-53, Argonne National Laboratory, Argonne, Illinois, October 1976. 48 pp.

The resulting emission factors are presented in Table 14 (50, 51). Due to the variability in analyses of different bituminous coals, elemental emissions could vary by several orders of magnitude from the reported values.

A discussion of the emissions data collected during field sampling and that reported in the literature follows. A description of the boiler sampled and the sampling and analytical techniques used is found in Appendix C.

Particulate Emissions

The average particulate matter emission factor (in terms of coal ash content) determined by the MRC source assessment field sampling effort was over 1.5 times the value given in AP 42 (52). It is believed that this was due to the fact that coal fired during the particulate loading measurements had an ash content in excess of the average value determined from coal samples taken at the site. This is likely because only three coal samples were taken over a 2-week sampling period to determine the physical and chemical characteristics of the coal.

The field sampling data collected by MRC for controlled and uncontrolled emission factors listed in Table 14 show that the ESP effected a 98.3% reduction in particulate emissions. Particulate size distributions measured for uncontrolled and controlled emissions are listed in Table 15, which illustrate how the efficiency of the ESP decreases with decreasing particle size.

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(50) Gibbs, L. L., C. E. Zimmer, and J. M. Zoller. Source Inventory and Emission Factor Analysis, Volume I. EPA-450/3-75-082-a (PB 247 743), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, September 1974. 276 pp.

(51) Cato, G. A., H. J. Buening, C. C. DeVivo, B. G. Morton, and J. M. Robinson. Field Testing: Application of Combustion Modifications to Control Pollutant Emissions from Industrial Boilers, Phase I. EPA-650/2-74-078-a (PB 238 920), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, October 1974. 213 pp.

(52) Compilation of Air Pollutant Emission Factors, Second Edition. AP-42 (PB 264 194), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, February 1976.

TABLE 14. EMISSION FACTORS FOR INDUSTRIAL DRY BOTTOM BOILERS FIRING PULVERIZED BITUMINOUS COAL

	Literature data				MRC field sampling data		
Emission species	Uncontrolled emission factor,[a] g/kg	Controlled emission factor, g/kg	95% confidence limit, % of emission factor	Reference[c]	Coal composition, g/kg (%)	Uncontrolled emission factor,[b] g/kg	Controlled emission factor,[b] g/kg
Particulate	9.2A[d]	–[e]	9.6	50	(8.23)	14.6A[d]	0.22A[d]
NO_x	8.2	–[e]	13	50	–[f]	–[g]	–[g]
SO_x	19.2S[h]	–[e]	25	50	(0.91)	19S[h]	13S[h]
Sulfate[i]	–[e]	1.6×10^{-2}	–[e]	1	–[g]	2.3×10^{-2}	1.8×10^{-2}
CO	0	–[e]	–[j]	51	–[f]	–[k]	0[m]
Hydrocarbon	6×10^{-2}	–[e]	130	51	–[f]	2.5×10^{-2}	2.5×10^{-2}
POM (total)	2.5×10^{-4}	–[e]	–[n]	1	–[f]	–[k]	1.5×10^{-3}
POM (carcinogenic)[o]	–[e]	–[e]	–[e]		–[f]	–[k]	1.1×10^{-3}
PCB	–[e]	–[e]	–[e]		–[f]	0[p]	0[p]
Elements:							
Aluminum	1.8×10^{1}	1.8×10^{-1}[q]	–[r]		5.8	4.0	2.2×10^{-1}
Antimony	1.2×10^{-3}	1.2×10^{-3}[s]	–[r]		1.7×10^{-2}	4.2×10^{-2}[t]	1.6×10^{-2}
Arsenic	2.6×10^{-2}	2.6×10^{-2}[s]	–[r]		6.9×10^{-3}	8.6×10^{-3}[t]	1.5×10^{-3}
Barium	1.0×10^{-1}	1.0×10^{-3}[q]	–[r]		5.4×10^{-2}	3.6×10^{-2}	4.1×10^{-3}
Beryllium	2.1×10^{-3}	–[e]	–[r]		4.4×10^{-3}	1.9×10^{-4}	2.5×10^{-5}
Bismuth	$<1.0 \times 10^{-4}$	$<1.0 \times 10^{-6}$[q]	–[r]		–[g]	–[g]	–[g]
Boron	2.9×10^{-2}	–[e]	–[r]		1.3×10^{-2}	2.9×10^{-2}[t]	1.6×10^{-2}[t]
Bromine	1.1×10^{-2}	1.1×10^{-2}[s]	–[r]		–[g]	–[g]	–[g]
Cadmium	6.8×10^{-4}	6.8×10^{-4}[s]	–[r]		1.4×10^{-3}	3.6×10^{-3}[t]	4.8×10^{-4}
Calcium	1.3	1.3×10^{-2}[q]	–[r]		7.2×10^{-1}	9.1×10^{-1}[t]	4.5×10^{-2}
Cerium	1.4×10^{-2}	1.4×10^{-4}[q]	–[r]		–[g]	–[g]	–[g]
Cesium	2.5×10^{-2}	2.5×10^{-4}[q]	–[r]		–[g]	–[g]	–[g]
Chlorine	7.3×10^{-1}	7.3×10^{-1}[s]	–[r]		–[g]	–[g]	–[g]
Chromium	2.0×10^{-2}	2.0×10^{-3}[u]	–[r]		1.6×10^{-2}	4.1×10^{-2}[t]	3.6×10^{-2}[t]
Cobalt	6.8×10^{-3}	6.8×10^{-5}[q]	–[r]		7.2×10^{-2}	1.5×10^{-2}	1.7×10^{-3}
Copper	2.2×10^{-2}	2.2×10^{-2}[s]	–[r]		4.4×10^{-2}	3.9×10^{-2}	2.8×10^{-3}
Dysprosium	1.4×10^{-3}	–[e]	–[r]		–[g]	–[g]	–[g]
Erbium	2.6×10^{-4}	–[e]	–[r]		–[g]	–[g]	–[g]
Europium	5.9×10^{-4}	5.9×10^{-6}[q]	–[r]		–[g]	–[g]	–[g]
Fluorine	7.8×10^{-2}	7.8×10^{-2}[s]	–[r]		–[g]	–[g]	–[g]
Gadolinium	1.0×10^{-3}	–[e]	–[r]		–[g]	–[g]	–[g]
Gallium	6.5×10^{-3}	6.5×10^{-3}[s]	–[r]		–[g]	–[g]	–[g]
Germanium	4.8×10^{-3}	–[e]	–[r]		–[g]	–[g]	–[g]
Gold	$<1.0 \times 10^{-4}$	–[e]	–[r]		–[g]	–[g]	–[g]
Hafnium	1.2×10^{-3}	1.2×10^{-5}[q]	–[r]		–[g]	–[g]	–[g]
Holmium	2.1×10^{-4}	–[e]	–[r]		–[g]	–[g]	–[g]
Iodine	1.1×10^{-3}	–[e]	–[r]		–[g]	–[g]	–[g]
Iridium	$<2.0 \times 10^{-4}$	–[e]	–[r]		–[g]	–[g]	–[g]
Iron	1.9×10^{1}	1.9×10^{-1}[q]	–[r]		1.8	3.4[t]	2.7×10^{-1}
Lanthanum	9.3×10^{-3}	9.3×10^{-5}[q]	–[r]		–[g]	–[g]	–[g]
Lead	1.5×10^{-2}	1.5×10^{-2}[s]	–[r]		1.2×10^{-2}	1.8×10^{-2}	2.0×10^{-3}
Lithium	2.7×10^{-2}	–[e]	–[r]		–[g]	–[g]	–[g]
Lutetium	1.2×10^{-4}	–[e]	–[r]		–[g]	–[g]	–[g]
Magnesium	6.9×10^{-1}	6.9×10^{-3}[q]	–[r]		3.2×10^{-1}	3.2×10^{-1}	2.0×10^{-2}
Manganese	5.9×10^{-1}	5.9×10^{-3}[q]	–[r]		1.3×10^{-2}	1.5×10^{-2}[t]	1.6×10^{-2}[t]
Mercury	2.4×10^{-4}	2.4×10^{-4}[s]	–[r]		5.0×10^{-4}	4.2×10^{-5}	5.0×10^{-5}
Molybdenum	3.1×10^{-3}	3.1×10^{-3}[s]	–[r]		8.5×10^{-3}	1.1×10^{-2}[t]	2.7×10^{-3}
Neodymium	1.2×10^{-2}	–[e]	–[r]		–[g]	–[g]	–[g]
Nickel	1.5×10^{-2}	1.5×10^{-3}[u]	–[r]		4.2×10^{-2}	4.5×10^{-2}[t]	2.3×10^{-2}[t]
Niobium	5.4×10^{-3}	5.4×10^{-5}[q]	–[r]		–[g]	–[g]	–[g]
Osmium	$<2.0 \times 10^{-4}$	–[e]	–[r]		–[g]	–[g]	–[g]
Palladium	$<1.0 \times 10^{-4}$	–[e]	–[r]		–[g]	–[g]	–[g]
Phosphorous	9.2×10^{-2}	–[e]	–[r]		8.8×10^{-2}	1.6×10^{-1}[t]	1.7×10^{-2}
Platinum	$<3.0 \times 10^{-4}$	–[e]	–[r]		–[g]	–[g]	–[g]
Potassium	2.3	2.3×10^{-2}[q]	–[r]		–[g]	–[g]	–[g]
Praeseodymium	2.1×10^{-3}	–[e]	–[r]		–[g]	–[g]	–[g]
Rhenium	$<2.0 \times 10^{-4}$	–[e]	–[r]		–[g]	–[g]	–[g]
Rhodium	$<1.0 \times 10^{-4}$	–[e]	–[r]		–[g]	–[g]	–[g]

(continued)

TABLE 14 (continued)

	Literature data				MRC field sampling data		
Emission species	Uncontrolled emission factor,[a] g/kg	Controlled emission factor, g/kg	95% confidence limit, % of emission factor	Reference[c]	Coal composition, g/kg (%)	Uncontrolled emission factor,[b] g/kg	Controlled emission factor,[b] g/kg
Rubidium	3.7×10^{-2}	3.7×10^{-4}[q]	–[r]		–[g]	–[g]	–[g]
Ruthenium	$<1.0 \times 10^{-4}$	–[e]	–[r]		–[g]	–[g]	–[g]
Samarium	1.9×10^{-3}	1.9×10^{-5}[q]	–[r]		–[g]	–[g]	–[g]
Scandium	5.1×10^{-3}	5.1×10^{-5}[q]	–[r]		–[g]	–[g]	–[g]
Selenium	4.5×10^{-3}	4.5×10^{-3}[s]	–[r]		1.0×10^{-3}	3.4×10^{-3}[t]	1.6×10^{-3}[t]
Silicon	2.7×10^{1}	2.7×10^{-1}[q]	–[r]		1.1×10^{-1}	3.1×10^{-2}	5.1×10^{-3}
Silver	2.5×10^{-5}	–[e]	–[r]		6.2×10^{-2}	1.2×10^{-1}[t]	8.5×10^{-4}
Sodium	3.3×10^{-1}	3.3×10^{-2}[u]	–[r]		3.4×10^{-1}	1.9×10^{-1}	5.5×10^{-2}
Strontium	1.0×10^{-1}	1.0×10^{-3}[q]	–[r]		6.8×10^{-2}	1.0×10^{-1}[t]	4.4×10^{-3}
Tantalum	9.5×10^{-4}	9.5×10^{-6}[q]	–[r]		–[g]	–[g]	–[g]
Tellurium	3.4×10^{-4}	–[e]	–[r]		–[g]	–[g]	–[g]
Terbium	3.2×10^{-4}	–[e]	–[r]		–[g]	–[g]	–[g]
Thallium	1.0×10^{-4}	1.0×10^{-4}[s]	–[r]		–[g]	–[g]	–[g]
Thorium	4.8×10^{-3}	4.8×10^{-5}[q]	–[r]		–[g]	–[g]	–[g]
Thulium	$<1.0 \times 10^{-4}$	–[e]	–[r]		–[g]	–[g]	–[g]
Tin	2.4×10^{-3}	2.4×10^{-5}[q]	–[r]		1.2×10^{-1}	2.0×10^{-1}[t]	1.3×10^{-2}
Titanium	8.1×10^{-1}	8.1×10^{-3}[q]	–[r]		3.7×10^{-1}	2.6×10^{-1}	9.9×10^{-3}
Tungsten	2.8×10^{-4}	–[e]	–[r]		–[g]	–[g]	–[g]
Uranium	1.4×10^{-3}	–[e]	–[r]		–[g]	–[g]	–[g]
Vanadium	2.0×10^{-2}	2.0×10^{-3}[u]	–[r]		7.8×10^{-2}	6.4×10^{-2}	4.0×10^{-3}
Ytterbium	9.8×10^{-4}	–[e]	–[r]		–[g]	–[g]	–[g]
Yttrium	1.1×10^{-2}	1.1×10^{-4}[q]	–[r]		–[g]	–[g]	–[g]
Zinc	1.8×10^{-2}	1.8×10^{-2}[s]	–[r]		1.9×10^{-2}	1.6×10^{-2}	4.2×10^{-3}
Zirconium	5.0×10^{-2}	5.0×10^{-4}[q]	–[r]		–[g]	–[g]	–[g]

[a] Uncontrolled emission factors for elemental emissions are based on average elemental concentrations in coal (see Table 12) assuming 100% of each element is emitted.

[b] No confidence limits are applied because only one source was sampled. Most values are averages of two measurements. Blanks indicate no emission measurement made.

[c] References for uncontrolled elemental emission factors are given in Table 12.

[d] Ash content of coal as percent by weight.

[e] No information available.

[f] Not applicable because these species are products of combustion.

[g] No coal or emission measurements were made for these species during the field sampling effort.

[h] Sulfur content of coal as percent by weight.

[i] Water soluble sulfate.

[j] Three samples, all zero at a detection level of 1 ppm.

[k] Measurements of these species were obtained for controlled emissions only.

[m] Six samples, all zero at a detection level of 1 ppm.

[n] Estimate of unknown accuracy, estimated to be order of magnitude.

[o] POM compounds which are known to be carcinogenic or are in a class of POM's that contain known carcinogens.

[p] Two samples each of uncontrolled and controlled emissions, all zero at the detection levels shown in Table 18.

[q] These elements are equally distributed between the bottom ash and fly ash according to Table 13 and therefore occur in the larger fly ash particles. On this basis it is assumed that the controlled emissions of these elements are 1% of the concentrations found in coal.

[r] Confidence limits for these numbers are not available but the number of measurements upon which each value is based is found in Table 12.

[s] Elements having partioning behavior in Classes II or III according to Table 13. Controlled emissions are assumed to be equal to uncontrolled emissions.

[t] These values are higher than those measured for the coal feed either because of the variability in the concentration of this element in coal or because of the accuracy of the measurement method. Values for the elements B, Cr, Fe, Mo, and Ni are suspected of being high due to contamination from the sampling train.

[u] Elements with partioning behavior intermediate between Class I and Class II. Controlled emissions are assumed to be 10% of uncontrolled emissions.

TABLE 15. SASS[a] PARTICLE SIZE DATA REPORTED AS A PERCENT OF THE TOTAL PARTICULATE MASS EMISSIONS

Particle size μm	Weight percent of uncontrolled emissions	Weight percent of controlled emissions
<1	1.3	3.9
1 to 3	12.9	41.2
3 to 10	39.3	36.3
>10	46.6	18.8

[a] Source assessment sampling system.

Nitrogen Oxides Emissions

Emissions of nitrogen oxides were not measured during the MRC sampling effort because of the extensive work done in this area by KVB, Inc. (51, 53), and because such data do not provide an insight into any of the other less characterized pollutants, as is the case with particulate data and trace elements, or sulfur oxides data and particulate sulfates. In general, emission factors for nitrogen oxides vary greatly from boiler to boiler (54) and are not significantly dependent on boiler size (48). The reason for this is that nitrogen oxide (NO) formation depends primarily on the fuel nitrogen content rather than boiler operating parameters. Other factors that influence NO_x production include the amount of excess air used, temperature of the incoming combustion air, design of burners and heat transfer equipment, extent of ash deposition on the furnace walls, and extent of flue gas recirculation, if used (55). On the basis of boiler heat input, nitrogen oxides emission factors for industrial coal-fired units have been measured in the range of 100 ng/J to 562 ng/J (48).

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(53) Cato, G. A., L. J. Muzio, and D. E. Shore. Field Testing: Application of Combustion Modifications to Control Pollutant Emissions from Industrial Boilers, Phase II. EPA-600/2-76-086-a (PB 253 500), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, April 1976. 270 pp.

(54) ensenbaugh, J. S., and J. Jonakin. Effect of Combustion Conditions on Nitric-Oxide Formation in Boiler Furnaces. ASME Paper No. 60-WA-334, presented at the 1960 Winter Annual Meeting of the American Society of Mechanical Engineers, New York, New York, November 1960. 7 pp.

(55) Rawdon, A. H., and R. S. Sadowski. An Experimental Corelation of Oxides of Nitrogen Emissions from Power Boilers Based on Field Data. Journal of Engineering for Power, Transactions of the ASME, 95(A-3):165-170, 1973.

Sulfur Oxides and Particulate Sulfate Emissions

Emission factors calculated from the sampling data for sulfur dioxide (SO_2), sulfur trioxide (SO_3), and particulate sulfate ($SO_4^=$) are listed in Table 16 for each of the runs made. The sulfur dioxide concentrations measured ahead of the ESP show little variance, and the average emission factor of 17.0 g/kg agrees well with the published (45) emission factor (19.2 x 0.91% S = 17.5 g/kg). The emission measurements made after the ESP show considerable variance among themselves and, when averaged, are about 30% lower than measurements at the inlet. The inlet and outlet measurements were not made simultaneously, and the observed differences could be the result of variations in the sulfur and trace element content of the coal. A statistical analysis of the average emission factors for all three sulfur species, before and after the ESP, reveals no significant difference in the values. The number of data points is too small to draw any conclusions.

TABLE 16. SULFUR OXIDES AND PARTICULATE SULFATE EMISSION FACTORS

	Emission factors, g/kg of coal		
Sampling run number	SO_2	SO_3	Particulate sulfate as SO_4
Inlet to ESP			
S1	16.8	0.019	0.019
S2	17.4	0.017	0.021
S3	16.9	0.018	0.027
Inlet averages	17.0	0.018	0.022
Outlet of ESP			
S4	14.1	0.023	0.024
S5	6.1	0.079	0.0076
S6	9.9	0.119	0.025
S7	16.5	0.031	0.0031
Outlet averages	11.7	0.063	0.015

The particulate sulfate measurements made at the ESP outlet also show more variance than those taken at the inlet. However, on the average there appears to be a 35% reduction after the control unit. This reduction is much lower than expected, particularly when compared to the 98% reduction observed for total particulate matter, indicating that the sulfate may concentrate on the smaller particles.

Carbon Monoxide Emissions

No carbon monoxide was measured at a detection level of 1 ppm. This agrees with other emission measurements made under steady-state baseload operation (47).

Hydrocarbon Emissions

Analyses of two integrated gas samples provided an average total gaseous hydrocarbon emission factor of 0.025 g/kg with less than 10% deviation between samples. A gas chromatographic analysis for C_1 through C_6 hydrocarbons showed no measurable peaks at a detection limit of 1 ppm.

A C_7 through C_{16} gas chromatographic analysis performed on an organic extract of the particulate matter collected by the SASS train and the XAD2 resin from the organic module for each SASS run revealed the presence of four to seven organic compounds in each sample. These appeared to be in the C_7 - C_9 and C_{14} - C_{16} ranges. Concentrations were estimated for each compound, from which an average total organic emission factor for the C_7 - C_{16} range was calculated to be 0.068 g/kg.

POM and PCB Emissions

A number of POM compounds were detected and are listed in Table 17 along with their individual emission factors and carcinogenic potential (56). Values represent the average of two measurements. The uncontrolled POM measurements were determined to be in error[a] and were discarded; therefore, the emission factors presented are for controlled emissions only. However, it has been reported in the literature that effluent POM concentrations do not display significant changes on passage through particulate controls, including precipitators (29). This was recently verified by Monsanto Research Corporation (MRC) when sampling POM emissions from utility boilers (57).

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[a] One measurement showed unrealistically high POM concentrations while the other showed very low POM levels. These differences could not be resolved, so the uncontrolled measurements were discarded in favor of the uncontrolled measurements which showed good agreement between the two runs.

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(56) Biologic Effects of Atmospheric Pollutants - Particulate Polycyclic Organic Matter. National Academy of Sciences, Washington, D.C., 1972. 361 pp.

(57) Personal communication with D. G. DeAngelis, Monsanto Research Corporation, Dayton, September 1977.

TABLE 17. CONTROLLED POM EMISSION FACTORS[a]

POM	Detection limit, μg/kg	Emission factor, μg/kg
Dibenzothiophene	0.8	4
Anthracene/phenanthrene	0.8	159
Methylanthracenes/phenanthrenes	1.7	10
Dimethylanthracenes/phenanthrenes	0.8	3
Fluoranthene	0.8	164
Pyrene	0.8	-[b]
Methylfluoranthenes/pyrenes	0.8	19
Benzo(c)phenanthrene	0.8	5[c]
Chrysene/benz(a)anthracene	0.8	617[c]
Dimethylbenz(a)anthracenes	5.0	29[c]
Benzofluoranthenes	0.8	329[c]
Benzopyrenes (and perylene)	0.8	-[b,c]
Methylcholanthrenes	5.0	85[c]
Indeno(1,2,3-c,d)pyrene	0.8	3[c]
Dibenz(a,h)anthracene (or isomers)	0.8	13[c]
Dibenzo(c,g)carbazole	3.3	-[b,c]
Dibenzopyrenes	3.3	22[c]
Methylchrysenes (or isomers)	1.7	37
Anthanthrene/benzo(ghi)perylene	1.7	-[b]
Total POM		1,499
Total carcinogenic POM		1,103

[a] Average of duplicate analyses of two measurements.

[b] Not detected.

[c] These groups contain known carcinogens (56).

It is difficult to compare the POM values obtained by sampling with previously published emission values due to recent advances in analytical techniques. Using the only set of quantitative POM values found in the literature for industrial boilers (58) and some utility data (59), such a comparison indicates that POM emissions from industrial boilers are an order of magnitude higher than those from utilities, as has been suggested in the literature (1). This is also supported by preliminary data obtained for the Source Assessment on dry bottom utility boilers firing pulverized bituminous coal (57).

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(58) Hangebrauck, R. P., D. J. vonLehmden, and J. E. Meeker. Emissions of Polynuclear Hydrocarbons and Other Pollutants from Heat-Generation and Incineration Processes. Journal of the Air Pollution Control Association, 14(7):267-278, 1964.

(59) Hangebrauck, R. P. D. J. vonLehmden, and J. E. Meeker. Sources of Polynuclear Hydrocarbons in the Atmosphere. Public Health Service Publication 999-AP-33 (PB 174 706), U.S. Department of Health, Education, and Welfare, Cincinnati, Ohio, 1967. 44 pp.

No PCB emissions were found. Table 18 lists the analytical detection limits for the method used in the PCB analysis.

TABLE 18. DETECTION LIMITS FOR PCB COMPOUNDS EXPRESSED AS MINIMUM DETECTABLE EMISSION FACTORS

PCB	Detection limit, μg/kg
Chlorobiphenyls	2.5
Dichlorobiphenyls	0.3
Trichlorobiphenyls	1.5
Tetrachlorobiphenyls	1.5
Pentachlorobiphenyls	0.3
Hexachlorobiphenyls	2.5
Heptachlorobiphenyls	0.7
Octachlorobiphenyls	0.7
Nonachlorobiphenyls	1.0
Decachlorobiphenyls	0.8

Elemental Emissions

Uncontrolled elemental emission factors for this source category as defined are not available in the literature. Therefore, the the emission factors listed in Table 14 under the heading of Literature Data were estimated based on the average coal composition data in Table 12 (24-27). It was assumed that 100% of each element was emitted on combustion.

Although one set of measurements has been reported for elemental emissions after controls, the data are not considered representative of best control because the control device was a cyclone of 65% efficiency (47). Therefore, to supplement data gathered in MRC's test program, controlled elemental emission factors were estimated based on partitioning behavior (see Table 13). Those elements not enriched in the fly ash (Class I) were assigned a controlled emission factor of 1% of the uncontrolled valve. For elements falling between Class I and Class II, controlled emissions were estimated to be 10% of the uncontrolled figures. For Classes II and III, it was assumed that controlled and uncontrolled emissions were equal.

Elemental emission factors from the MRC sampling program are also reported in Table 14. In general the uncontrolled emission factors are comparable to the corresponding concentrations in the feed coal, although several elements have values that differ by a factor of two or more. In regard to the low uncontrolled emission factor for silicon (relative to its concentration in coal), it should be noted that when the ash samples were digested for analysis an insoluble residue remained after repeated attempts at a rigorous acid digestion. The undigested material was assumed to be largely silicon, although it may have contained other elements. Also, the concentrations measured for chromium, nickel, molybdenum, and boron may be high due to contamination of the samples by the sampling train. This is further discussed in Section 8.

An average element control efficiency of 75% was measured for the ESP. This is somewhat lower than the measured particulate control efficiency (98.3%), indicating that many of these elements are concentrating on the smaller particles.

Table 19 shows the percentage of each of the measured elements entering the boiler in the feed coal that was found in the uncontrolled and controlled emissions during the MRC sampling program. The percent reduction in concentrations of the elements in the flue gas achieved by the ESP is also shown.

TABLE 19. PERCENTAGE OF EACH ELEMENT ENTERING THE BOILER FOUND IN THE FLUE GAS BEFORE AND AFTER CONTROLS

Element	Percent of element in uncontrolled emissions	Percent of element in controlled emissions	Percent reduction in flue gas concentration after the ESP
Aluminum	69	3.8	95
Antimony	250	94	83
Arsenic	120	22	62
Barium	67	7.6	89
Beryllium	4.3	0.57	87
Boron[a]	220	120	45
Cadmium	260	34	87
Calcium	120	6.3	95
Chromium[a]	260	230	12
Cobalt	21	2.4	89
Copper	89	6.4	93
Iron[a]	190	15	92
Lead	150	17	89
Magnesium	100	6.3	94
Manganese	120	120	0
Mercury	84	93	0
Molybdenum[a]	130	32	75
Nickel[a]	110	55	49
Phosphorus	180	19	89
Selenium	340	160	53
Silicon[a]	28	4.6	84
Silver	190	14	99
Sodium	56	16	71
Strontium	150	6.4	96
Tin	170	11	94
Titanium	70	2.7	96
Vanadium	82	5.1	94
Zinc	84	22	74

[a] These values may be in error due to sample contamination. See Section 8.

POTENTIAL ENVIRONMENTAL EFFECTS

Air emissions released during the combustion of pulverized bituminous coal in dry bottom industrial boilers enter the atmosphere and are dispersed throughout the environment. These emissions have an adverse impact on the quality of air, water, and land resources, property, vegetation, and animal and human health. While the fate and environmental effects of many trace pollutants are not known, those of the major species are well documented (60-62).

The purpose of this segment is to evaluate the potential environmental effects due to air emissions from an average plant in this source category and from all boilers in the category. This is done by defining an average source and the range of actual sources and then comparing the expected maximum ground level concentrations of emitted pollutants (based on the emission factors in Table 14) with air quality standards. In addition, the percent contributions of this source category to the state and national emission burdens of criteria pollutants are presented.

Average Plant and Range of Actual Plants

A range of plants can be defined as discussed in Section 3. For this report, the average source is defined as an industrial dry bottom boiler firing pulverized Appalachian bituminous coal at a rate of 222 GJ/hr. The stack height of the boiler is 45.7 m (11). The firing rate is based on an average firing capacity value calculated from a National Emissions Data System (NEDS) listing for this source type (5), and the stack height is based on an average obtained from Reference 11.

Sources in the NEDS listing (see Appendix A) range from a capacity of 1 GJ/hr with a stack height of 6.7 m to a capacity of 1,900 GJ/hr with a stack height of 67.1 m.

Source Severity

The potential environmental effects of air emissions from a point source can be measured in several ways. The method used here is to determine the maximum ground level concentration of

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(60) Air Pollution; Volume I: Air Pollution and Its Effects, Second Edition, A. C. Stern, ed. Academic Press, New York, New York, 1968. 694 pp.

(61) Leighton, P. A. Photochemistry of Air Pollution. Academic Press, New York, New York, 1961. 300 pp.

(62) Seinfeld, J. H. Air Pollution - Physical and Chemical Fundamentals. McGraw-Hill Book Company, New York, New York, 1975. 523 pp.

each emission species downwind from the average plant and compare this value to the primary ambient air quality standard for criteria emissions (63) or to a reduced threshold limit value (TLV) (64) for the noncriteria emission species.

The comparison is called source severity, S_a, and is defined as

$$S_a = \frac{\bar{\chi}_{max}}{F} \tag{2}$$

where $\bar{\chi}_{max}$ = maximum time-averaged ground level concentration for each emission species, g/m³
F = primary ambient air quality standard for criteria pollutants (particulate matter, sulfur oxides, nitrogen oxides, carbon monoxide, and hydrocarbons), g/m³

or

F = TLV x 8/24 x 1/100, for noncriteria emission species, g/m³ (3)

where TLV = threshold limit value for each species, g/m³
8/24 = correction factor to adjust the TLV to a 24-hr exposure level
1/100 = safety factor

The value of $\bar{\chi}_{max}$ for an average source is calculated from

$$\bar{\chi}_{max} = \chi_{max} \left(\frac{t_o}{t} \right)^{0.17} \tag{4}$$

where $\chi_{max} = \dfrac{2\,Q}{\pi e \bar{u} H^2}$ for elevated point sources (5)

and

Q = emission rate, g/s
π = 3.14
e = 2.72
$\bar{u}$ = average wind speed, 4.5 m/s (national average)
t_o = short-term averaging time, 3 min
t = averaging time, min
H = height of emission release, m

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(63) Code of Federal Regulations, Title 42 - Public Health, Chapter IV - Environmental Protection Agency, Part 410 - National Primary and Secondary Ambient Air Quality Standards, April 28, 1971. 16 pp.

(64) TLVs® Threshold Limit Values for Chemical Substances and Physical Agents in the Workroom Environment with Intended Changes for 1976. American Conference of Governmental Industrial Hygienists, Cincinnati, Ohio, 1976. 97 pp.

The equation for χ_{max} (Equation 5) is derived from the general plume dispersion equation for an elevated point source for average U.S. atmospheric stability conditions (65).

The maximum severity of pollutants may be calculated using the mass emission rate, Q, the height of the emissions, H, and the TLVs (used for noncriteria pollutants). The equations summarized in Table 20 are developed in Appendix D.

TABLE 20. POLLUTANT SEVERITY EQUATIONS FOR ELEVATED SOURCES

Pollutant	Severity equation
Particulate matter	$S_p = \frac{70\ Q}{H^2}$
SO_x	$S_{SO_x} = \frac{50\ Q}{H^2}$
NO_x	$S_{NO_x} = \frac{315\ Q}{H^{2.1}}$
Hydrocarbons	$S_{HC} = \frac{162\ Q}{H^2}$
CO	$S_{CO} = \frac{0.78\ Q}{H^2}$
Others	$S_a = \frac{5.5\ Q}{TLV \bullet H^2}$

The ambient air quality standards used for criteria pollutants and the TLVs used for noncriteria pollutants are listed in Tables 21 and 22 respectively.

Emission factors used for the severity calculations were selected from Table 14 using the following priority: 1) MRC field sampling data for controlled emissions, 2) literature data for controlled emissions (estimated), or 3) literature data for uncontrolled emissions. Certain deviations from this order of priorities occurred as noted below:

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(65) Turner, D. B. Workbook of Atmospheric Dispersion Estimates. Public Health Service Publication 999-AP-26 (PB 191 482), U.S. Department of Health, Education, and Welfare, Cincinnati, Ohio, 1969. 62 pp.

- Because the particulate emission factor as a function of coal ash content was anomolously high for the MRC test results, the literature value from Table 14 was used instead. The uncontrolled particulate emission factor of 9.2A g/kg was multiplied by the ESP collection efficiency observed in the MRC tests (i.e., 98.3%) to give a controlled emission factor of 0.16A g/kg.

- The controlled SO_x emission factor from the MRC tests was not used because this behavior (i.e., a decrease in SO_x following an ESP) has not been reported previously in the literature. An uncontrolled value of 19S g/kg was used to calculate severity.

- Literature values were used for the elements boron, chromium, iron, molybdenum, nickel and silicon because the test results were suspect, as noted previously.

TABLE 21. AMBIENT AIR QUALITY STANDARDS FOR CRITERIA POLLUTANTS (63)

Emission	Ambient air quality standard, mg/m^3
Particulate matter	0.260
NO_x	0.100
SO_x	0.365
CO	40.0
Hydrocarbons	0.160[a]

[a] There is no primary ambient air quality standard for hydrocarbons. The value of 160 μ/m^3 used for hydrocarbons in this report is a recommended guideline for meeting the primary ambient air quality standard for oxidants.

Emission rates, Q, were calculated from emission factor data. For example, the average plant generates 222 GJ/hr; therefore:

$$Q = 222\ \text{GJ/hr} \bullet \frac{\text{hr}}{3{,}600\ \text{s}} \bullet \frac{\text{kg coal}}{30 \times 10\ \ \text{J}} \bullet \frac{\text{EF g}}{\text{Kg coal}}$$

$$Q = 2.06 \bullet \text{EF}$$

where EF = emission factor, g/kg

Similarly, the emission rates from the smallest (1 GJ/hr) and largest (1,900 GJ/hr) sources reported in NEDS were calculated:

$$Q_{small} = 0.00976 \bullet EF$$

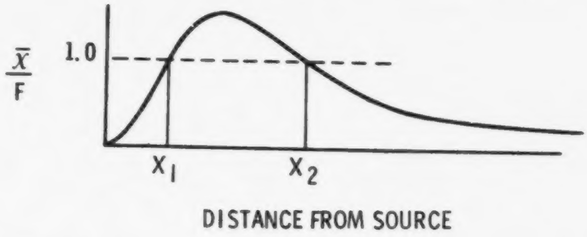
$$Q_{large} = 17.5 \bullet EF$$

This provides a range of severities for the whole source category. The severities for the average, smallest, and largest plants, and the values used to calculate them, are presented in Tables 23, 24, and 25, respectively. For the average plant, the only emissions with severities greater than 1.0 are NO_x, SO_x, and carcinogenic POM's.

For source types with significant plume rise, the value of H in Equation 5 must be corrected to include the plume rise. An examination of NEDS data for this source shows that the increase in emission height for a typical plant is ∿35%. However, for boilers that do not recover heat from the stack gas, the plume rise may exceed the stack height.

Affected Population

Dispersion equations predict that the average ground level concentration, $\overline{\chi}$, varies with the distance, x, downwind from a source. For elevated sources, $\overline{\chi}$ is zero at the source (where $x = 0$), increases to some maximum value, $\overline{\chi}_{max}$, as x increases, and then falls back to zero as x approaches infinity. Therefore, a plot of $\overline{\chi}/F$ vs x will have the following appearance.



The affected population is defined as the number of nonplant persons around an average dry bottom industrial boiler firing pulverized bituminous coal who are exposed to $\overline{\chi}/F$ ratio greater than 0.05 or 1.0. A severity of ≥1.0 indicates exposure to a potentially hazardous concentration of a pollutant. The severity value of 0.05 allows for inherent uncertainties in measurement techniques, dispersion modeling, and health effects data. The mathematical derivation of the affected population calculation is presented in Appendix D. The number of persons within the exposed area was calculated using a population density of 470 persons/km². This value was calculated by weighting the county population densities of the sources listed in NEDS by the number

TABLE 22. THRESHOLD LIMIT VALUES USED FOR NONCRITERIA POLLUTANTS (64)

Emission	TLV, mg/m^3	Compound used for TLV
POM	0.2	POM
POM (carcinogenic)	0.001	Carcinogen[a]
PCB	0.5	Chlorodiphenyl (54% chlorine) skin
Sulfate	1.0	Sulfuric acid, H_2SO_4
Elements:		
Aluminum	10	Alundum, Al_2O_3
Arsenic	0.5	Arsenic and compounds
Antimony	0.5	Antimony and compounds
Barium	0.5	Barium (soluble compounds)
Beryllium	0.002	Beryllium
Bismuth	10	-[b]
Boron	10	Boron oxide
Bromine	0.7	Bromine
Cadmium	0.05	Cadmium oxide fume
Calcium	5	Calcium oxide
Cerium	10	-[b]
Cesium	2	Cesium hydroxide
Chlorine	7	Hydrogen chloride
Chromium	0.1	Chromic acid and chromates
Cobalt	0.1	Cobalt metal, dust and fume
Copper	1	Copper, dusts and mists
Dysprosium	10	-[b]
Erbium	10	-[b]
Europium	10	-[b]
Fluorine	2	Fluorine
Gadolinum	10	-[b]
Gallium	10	-[b]
Germanium	10	-[b]
Gold	10	-[b]
Hafnium	0.5	Hafnium
Holmium	10	-[b]
Iodine	1	Iodine
Iridium	10	-[b]
Iron	5	Iron oxide fume
Lanthanum	10	-[b]
Lead	0.15	Lead, inorganic fumes and dusts
Lithium	10	-[b]
Lutetium	10	-[b]
Magnesium	10	Magnesium oxide fume
Manganese	5	Manganese and compounds
Mercury	0.05	All forms except alkyl

(continued)

TABLE 22 (continued)

Emission	TLV, mg/m^3	Compound used for TLV
Molybdenum	5	Soluble compounds
Neodymium	10	–[b]
Nickel	0.1	Soluble compounds
Niobium	10	–[b]
Osmium	0.002	Osmium tetoxide
Palladium	10	–[b]
Phosphorus	1	Phosphoric acid
Platinum	0.002	Soluble salts
Potassium	2	Potassium hydroxide
Praeseodymium	10	–[b]
Rhenium	10	–[b]
Rhodium	0.1	Metal fumes and dusts
Rubidium	10	–[b]
Ruthenium	10	–[b]
Samarium	10	–[b]
Scandium	10	–[b]
Selenium	0.2	Selenium compounds
Silicon	10	Silicon
Silver	0.01	Metal and soluble compounds
Sodium	2	Sodium hydroxide
Strontium	10	–[b]
Tantalum	5	Tantalum
Tellurium	0.1	Tellurium
Terbium	10	–[b]
Thallium	0.1	Thallium soluble compounds
Thorium	10	–[b]
Thulium	10	–[b]
Tin	10	Tin oxide
Titanium	10	Titanium dioxide
Tungsten	1	Tungsten and compounds, soluble
Uranium	0.2	Soluble and insoluble compounds
Vanadium	0.5	Vanadium pentoxide dust, V_2O_5
Ytterbium	10	–[b]
Yttrium	1	Yttrium
Zinc	5	Zinc oxide fume
Zirconium	5	Zirconium compounds

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[a] Value for carcinogenic compounds corresponds approximately to the minimum detectable limit.

[b] For elements not having an appropriate TLV, the TLV for nuisance particulate, 10 mg/m^3, was used.

TABLE 23. EMISSION RATES AND SOURCE SEVERITIES OF AN AVERAGE PLANT [a]

Pollutant	Emission rate, g/s	Severity
Particulate[b]	3.6	1.2×10^{-1}
NO_x	1.7×10^{1}	1.7
SO_x[c]	9.0×10^{1}	2.2
CO	0.0	0.0
Hydrocarbons	5.2×10^{-2}	4.0×10^{-3}
POM (total)	3.1×10^{-3}	4.1×10^{-2}
POM (carcinogenic)	2.3×10^{-3}	6.0
PCB	0.0	0.0
Sulfate	3.7×10^{-2}	9.8×10^{-2}
Elements:		
Aluminum	4.5×10^{-1}	1.2×10^{-1}
Antimony	3.3×10^{-2}	1.7×10^{-1}
Arsenic	3.1×10^{-3}	1.6×10^{-2}
Barium	8.4×10^{-3}	4.4×10^{-2}
Beryllium	5.2×10^{-5}	6.8×10^{-2}
Bismuth	2.1×10^{-6}	5.4×10^{-7}
Boron	6.0×10^{-2}	1.6×10^{-2}
Bromine	2.3×10^{-2}	8.5×10^{-2}
Cadmium	9.9×10^{-4}	5.2×10^{-2}
Calcium	9.3×10^{-2}	4.9×10^{-2}
Cerium	2.9×10^{-4}	7.6×10^{-5}
Cesium	5.2×10^{-4}	6.8×10^{-4}
Chlorine	1.5	5.7×10^{-1}
Chromium	4.1×10^{-3}	1.1×10^{-1}
Cobalt	3.5×10^{-3}	9.2×10^{-2}
Copper	5.8×10^{-3}	1.5×10^{-2}
Dysprosium	2.9×10^{-3}	7.6×10^{-4}
Erbium	5.4×10^{-4}	1.4×10^{-4}
Europium	1.2×10^{-5}	3.2×10^{-6}
Fluorine	1.6×10^{-1}	2.1×10^{-1}
Gadolinium	2.1×10^{-3}	5.4×10^{-4}
Gallium	1.3×10^{-2}	3.5×10^{-3}
Germanium	9.9×10^{-3}	2.6×10^{-3}
Gold	2.1×10^{-4}	5.4×10^{-5}
Hafnium	2.5×10^{-5}	1.3×10^{-4}
Holmium	4.3×10^{-4}	1.1×10^{-4}
Iodine	2.3×10^{-3}	6.0×10^{-3}
Iridium	4.1×10^{-4}	1.1×10^{-4}
Iron	3.9×10^{-1}	2.1×10^{-1}
Lanthanum	1.9×10^{-4}	5.0×10^{-5}
Lead	4.1×10^{-3}	7.2×10^{-2}
Lithium	5.6×10^{-2}	1.5×10^{-2}
Lutetium	2.5×10^{-4}	6.5×10^{-5}
Magnesium	4.1×10^{-2}	1.1×10^{-2}

(continued)

TABLE 23 (continued)

Pollutant	Emission rate, g/s	Severity
Manganese	3.3×10^{-2}	1.7×10^{-2}
Mercury	1.0×10^{-4}	5.4×10^{-3}
Molybdenum	6.4×10^{-3}	3.4×10^{-3}
Neodymium	2.5×10^{-2}	6.5×10^{-3}
Nickel	3.1×10^{-3}	8.1×10^{-2}
~~Niobium~~	~~1.1×10^{-4}~~	~~2.9×10^{-5}~~
Osmium	4.1×10^{-4}	5.4×10^{-1}
Palladium	2.1×10^{-4}	5.4×10^{-5}
Phosphorus	3.5×10^{-2}	9.2×10^{-2}
Platinum	6.2×10^{-4}	8.1×10^{-1}
Potassium	4.7×10^{-2}	6.2×10^{-2}
Praeseodymium	4.3×10^{-3}	1.1×10^{-3}
Rhenium	4.1×10^{-4}	1.1×10^{-4}
Rhodium	2.1×10^{-4}	5.4×10^{-3}
Rubidium	7.6×10^{-4}	2.0×10^{-4}
Ruthenium	2.1×10^{-4}	5.4×10^{-5}
Samarium	3.9×10^{-5}	1.0×10^{-5}
Scandium	1.1×10^{-4}	2.8×10^{-5}
Selenium	3.3×10^{-3}	4.3×10^{-2}
Silicon	5.6×10^{-1}	1.5×10^{-1}
Silver	1.8×10^{-3}	4.6×10^{-1}
Sodium	1.1×10^{-1}	1.5×10^{-1}
Strontium	9.1×10^{-3}	2.4×10^{-3}
Tantalum	2.0×10^{-5}	1.0×10^{-5}
Tellurium	7.0×10^{-4}	1.8×10^{-2}
Terbium	6.6×10^{-4}	1.7×10^{-4}
Thallium	2.1×10^{-4}	5.4×10^{-3}
Thorium	9.9×10^{-5}	2.6×10^{-5}
Thulium	2.1×10^{-4}	5.4×10^{-5}
Tin	2.7×10^{-2}	7.1×10^{-3}
Titanium	2.0×10^{-2}	5.4×10^{-3}
Tungsten	5.8×10^{-4}	1.5×10^{-3}
Uranium	2.9×10^{-3}	3.8×10^{-2}
Vanadium	8.2×10^{-3}	4.3×10^{-2}
Ytterbium	2.0×10^{-3}	5.1×10^{-4}
Yttrium	2.3×10^{-4}	6.0×10^{-4}
Zinc	8.7×10^{-3}	4.6×10^{-3}
Zirconium	1.0×10^{-3}	5.4×10^{-4}

[a] Emission height, H = 45.7 m;
design firing capacity = 222 GJ/hr.

[b] Based on an average ash content of 11.0% for Appalachian coal.

[c] Based on an average sulfur content of 2.3% for Appalachian coal.

TABLE 24. EMISSION RATES AND SOURCE SEVERITIES OF THE SMALLEST PLANT[a]

Pollutant	Emission rate, g/s	Severity
Particulate[b]	1.7×10^{-2}	2.6×10^{-2}
NO_x	8.0×10^{-2}	4.6×10^{-1}
SO_x[c]	4.3×10^{-1}	4.7×10^{-1}
CO	0.0	0.0
Hydrocarbons	2.4×10^{-4}	8.8×10^{-4}
POM (total)	1.5×10^{-5}	8.9×10^{-3}
POM (carcinogenic)	1.1×10^{-5}	1.3
PCB	0.0	0.0
Sulfate	1.8×10^{-4}	2.1×10^{-2}
Elements:		
Aluminum	2.1×10^{-3}	2.6×10^{-2}
Antimony	1.6×10^{-4}	3.8×10^{-2}
Arsenic	1.5×10^{-5}	3.6×10^{-3}
Barium	4.0×10^{-5}	9.8×10^{-3}
Beryllium	2.4×10^{-7}	1.5×10^{-2}
Bismuth	1.0×10^{-8}	1.2×10^{-7}
Boron	2.8×10^{-4}	3.4×10^{-3}
Bromine	1.1×10^{-4}	1.9×10^{-2}
Cadmium	4.7×10^{-6}	1.1×10^{-2}
Calcium	4.4×10^{-4}	1.1×10^{-2}
Cerium	1.4×10^{-6}	1.7×10^{-5}
Cesium	2.4×10^{-6}	1.5×10^{-4}
Chlorine	7.1×10^{-3}	1.2×10^{-1}
Chromium	2.0×10^{-5}	2.4×10^{-2}
Cobalt	1.7×10^{-5}	2.0×10^{-2}
Copper	2.7×10^{-5}	3.3×10^{-3}
Dysprosium	1.4×10^{-5}	1.7×10^{-4}
Erbium	2.5×10^{-6}	3.1×10^{-5}
Europium	5.8×10^{-8}	7.0×10^{-7}
Fluorine	7.6×10^{-4}	4.6×10^{-2}
Gadolinium	9.8×10^{-6}	1.2×10^{-4}
Gallium	6.3×10^{-5}	7.7×10^{-4}
Germanium	4.7×10^{-7}	5.7×10^{-5}
Gold	9.8×10^{-7}	1.2×10^{-5}
Hafnium	1.2×10^{-7}	2.9×10^{-5}
Holmium	2.1×10^{-6}	2.5×10^{-5}
Iodine	1.1×10^{-5}	1.3×10^{-3}
Iridium	2.0×10^{-6}	2.4×10^{-5}
Iron	1.8×10^{-3}	4.5×10^{-2}
Lanthanum	9.1×10^{-7}	1.1×10^{-5}
Lead	2.0×10^{-5}	1.6×10^{-2}
Lithium	2.6×10^{-4}	3.2×10^{-3}
Lutetium	1.2×10^{-6}	1.4×10^{-5}
Magnesium	2.0×10^{-4}	2.4×10^{-3}
Manganese	1.6×10^{-4}	3.8×10^{-3}

(continued)

TABLE 24 (continued)

Pollutant	Emission rate, g/s	Severity
Mercury	4.9×10^{-7}	1.2×10^{-3}
Molybdenum	3.0×10^{-5}	7.4×10^{-4}
Neodymium	1.2×10^{-4}	1.4×10^{-3}
Nickel	1.5×10^{-5}	1.8×10^{-2}
Niobium	5.3×10^{-7}	6.4×10^{-6}
Osmium	2.0×10^{-6}	1.2×10^{-1}
Palladium	9.8×10^{-7}	1.2×10^{-5}
Phosphorus	1.7×10^{-4}	2.0×10^{-2}
Platinum	2.9×10^{-6}	1.8×10^{-1}
Potassium	2.2×10^{-4}	1.4×10^{-2}
Praeseodymium	2.0×10^{-5}	2.5×10^{-4}
Rhenium	2.0×10^{-6}	2.4×10^{-5}
Rhodium	9.8×10^{-7}	1.2×10^{-3}
Rubidium	3.6×10^{-6}	4.4×10^{-5}
Ruthenium	9.8×10^{-7}	1.2×10^{-5}
Samarium	1.9×10^{-7}	2.3×10^{-6}
Scandium	5.0×10^{-7}	6.1×10^{-6}
Selenium	1.6×10^{-5}	9.5×10^{-3}
Silicon	2.6×10^{-3}	3.2×10^{-2}
Silver	8.3×10^{-6}	1.0×10^{-1}
Sodium	5.4×10^{-4}	3.3×10^{-2}
Strontium	4.3×10^{-5}	5.3×10^{-4}
Tantalum	9.3×10^{-8}	2.3×10^{-6}
Tellurium	3.3×10^{-6}	4.0×10^{-3}
Terbium	3.1×10^{-6}	3.8×10^{-5}
Thallium	9.8×10^{-7}	1.2×10^{-3}
Thorium	4.7×10^{-7}	5.7×10^{-6}
Thulium	9.8×10^{-7}	1.2×10^{-5}
Tin	1.3×10^{-4}	1.5×10^{-3}
Titanium	9.7×10^{-5}	1.2×10^{-3}
Tungsten	2.7×10^{-6}	3.3×10^{-4}
Uranium	1.4×10^{-5}	8.3×10^{-3}
Vanadium	3.9×10^{-5}	9.5×10^{-3}
Ytterbium	9.6×10^{-6}	1.2×10^{-4}
Yttrium	1.1×10^{-6}	1.3×10^{-4}
Zinc	6.7×10^{-5}	1.0×10^{-3}
Zirconium	4.9×10^{-6}	1.2×10^{-4}

[a] Emission height, H = 6.71 m;
design firing capacity = 1 GJ/hr.

[b] Based on an average ash content of 11.0% for Appalachian coal.

[c] Based on an average sulfur content of 2.3% for Appalachian coal.

TABLE 25. EMISSION RATES AND SOURCE SEVERITIES OF THE LARGEST PLANT[a]

Pollutant	Emission rate, g/s	Severity
Particulate[b]	3.1×10^{1}	4.7×10^{-1}
NO_x	1.4×10^{2}	6.6
SO_x[c]	7.6×10^{2}	8.5
CO	0.0	0.0
Hydrocarbons	4.4×10^{-1}	1.6×10^{-2}
POM (total)	2.6×10^{-2}	1.6×10^{-1}
POM (carcinogenic)	1.9×10^{-2}	2.4×10^{1}
PCB	0.0	0.0
Sulfate	3.2×10^{-1}	3.8×10^{-1}
Elements:		
Aluminum	3.9	4.5×10^{-1}
Antimony	2.8×10^{-1}	6.8×10^{-1}
Arsenic	2.6×10^{-2}	6.4×10^{-2}
Barium	7.2×10^{-2}	1.7×10^{-1}
Beryllium	4.4×10^{-4}	2.7×10^{-1}
Bismuth	1.8×10^{-5}	2.1×10^{-6}
Boron	5.1×10^{-1}	6.2×10^{-2}
Bromine	1.9×10^{-1}	3.3×10^{-1}
Cadmium	8.4×10^{-3}	2.0×10^{-1}
Calcium	7.9×10^{-1}	1.9×10^{-1}
Cerium	2.5×10^{-3}	3.0×10^{-4}
Cesium	4.4×10^{-3}	2.7×10^{-3}
Chlorine	1.3×10^{2}	2.2
Chromium	3.5×10^{-2}	4.3×10^{-1}
Cobalt	3.0×10^{-2}	3.6×10^{-1}
Copper	4.9×10^{-2}	6.0×10^{-2}
Dysprosium	2.5×10^{-2}	3.0×10^{-3}
Erbium	4.6×10^{-3}	5.5×10^{-4}
Europium	1.0×10^{-4}	1.3×10^{-5}
Fluroine	1.4	8.3×10^{-1}
Gadolinium	1.8×10^{-2}	2.1×10^{-3}
Gallium	1.1×10^{-1}	1.4×10^{-2}
Germanium	8.4×10^{-2}	1.0×10^{-2}
Gold	1.8×10^{-3}	2.1×10^{-4}
Hafnium	2.1×10^{-4}	5.1×10^{-4}
Holmium	3.7×10^{-3}	4.5×10^{-4}
Iodine	1.9×10^{-2}	2.3×10^{-2}
Iridium	3.5×10^{-3}	4.3×10^{-4}
Iron	3.3	8.1×10^{-1}
Lanthanum	1.6×10^{-3}	2.0×10^{-4}
Lead	3.5×10^{-2}	2.8×10^{-1}
Lithium	4.7×10^{-1}	5.8×10^{-2}
Lutetium	2.1×10^{-3}	2.6×10^{-4}
Magnesium	3.5×10^{-1}	4.3×10^{-2}
Manganese	2.8×10^{-1}	6.8×10^{-2}

(continued)

TABLE 25 (continued)

Pollutant	Emission rate, g/s	Severity
Mercury	8.8×10^{-4}	2.1×10^{-2}
Molybdenum	5.4×10^{-2}	1.3×10^{-2}
Neodymium	2.1×10^{-1}	2.6×10^{-2}
Nickel	2.6×10^{-2}	3.2×10^{-1}
Niobium	9.5×10^{-4}	1.2×10^{-4}
Osmium	3.5×10^{-3}	2.1
Palladium	1.8×10^{-3}	2.1×10^{-4}
Phosphorus	3.0×10^{-1}	3.6×10^{-1}
Platinum	5.3×10^{-3}	3.2
Potassium	4.0×10^{-1}	2.4×10^{-1}
Praeseodymium	3.7×10^{-2}	4.5×10^{-3}
Rhenium	3.5×10^{-3}	4.3×10^{-4}
Rhodium	1.8×10^{-3}	2.1×10^{-2}
Rubidium	6.5×10^{-3}	7.9×10^{-4}
Ruthenium	1.8×10^{-3}	2.1×10^{-4}
Samarium	3.3×10^{-4}	4.0×10^{-5}
Scandium	8.9×10^{-4}	1.1×10^{-4}
Selenium	2.8×10^{-2}	1.7×10^{-1}
Silicon	4.7	5.8×10^{-1}
Silver	1.5×10^{-2}	1.8
Sodium	9.6×10^{-1}	5.9×10^{-1}
Strontium	7.7×10^{-2}	9.4×10^{-3}
Tantalum	1.7×10^{-4}	4.0×10^{-5}
Tellurium	6.0×10^{-3}	7.2×10^{-2}
Terbium	5.6×10^{-3}	6.8×10^{-4}
Thallium	1.8×10^{-3}	2.1×10^{-2}
Thorium	8.4×10^{-4}	1.0×10^{-4}
Thulium	1.8×10^{-3}	2.1×10^{-4}
Tin	2.3×10^{-1}	2.8×10^{-2}
Titanium	1.7×10^{-1}	2.1×10^{-2}
Tungsten	4.9×10^{-3}	6.0×10^{-3}
Uranium	2.5×10^{-2}	1.5×10^{-1}
Vanadium	7.0×10^{-2}	1.7×10^{-1}
Ytterbium	1.7×10^{-2}	2.1×10^{-3}
Yttrium	1.9×10^{-3}	2.3×10^{-3}
Zinc	7.4×10^{-2}	1.8×10^{-2}
Zirconium	8.8×10^{-3}	2.1×10^{-3}

[a] Emission height, H = 67.1 m; design firing capacity = 1,900 GJ/hr.

[b] Based on an average ash content of 11.0% for Appalachian coal.

[c] Based on an average sulfur content of 2.3% for Appalachian coal.

of sources in that county (see Appendix A). Values for the affected population around the average plant are listed in Table 26 for pollutants with severities greater than 0.05 and 1.0.

TABLE 26. AFFECTED POPULATION FOR EMISSIONS WITH A SOURCE SEVERITY GREATER THAN 0.05 AND 1.0

Emission species	Affected population, persons	
	$S_a > 0.05$	$S_a > 1.0$
Particulate	2,500	0
NO_x	42,000	1,200
SO_x	63,000	2,200
Sulfate	1,900	0
POM (carcinogenic)	190,000	7,500
Elements:		
Aluminum	2,500	0
Antimony	3,900	0
Beryllium	1,000	0
Bromine	1,500	0
Cadmium	560	0
Chlorine	15,000	0
Chromium	2,200	0
Cobalt	1,700	0
Fluorine	5,000	0
Iron	5,000	0
Lead	1,200	0
Nickel	1,400	0
Osmium	14,000	0
Phosphorus	1,700	0
Platinum	22,000	0
Potassium	870	0
Silicon	3,200	0
Silver	12,000	0
Sodium	3,200	0

Contribution To Total State And National Emissions

The contributions of emissions from industrial dry bottom boilers firing pulverized bituminous coal to the total emission burdens of the states in which these boilers are located were calculated using state totals of the individual emission estimates presented in the NEDS listing (5). Controls applied to the boilers in this listing were considered in the estimation of these emissions. Where no values were given for a criteria pollutant in the NEDS for a particular boiler, a value was assigned based on the emission factors in Table 14. Total state and national emissions for the criteria pollutants emitted from stationary and mobile sources were obtained from Reference 66.

Table 27 shows the percent contributions of this source category to the five criteria emission burdens for each state in the NEDS listing and to the national totals.

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(66) 1972 National Emissions Report; National Emissions Data System (NEDS) of the Aerometric and Emissions Reporting System (AEROS). EPA-450/2-74-012 (PB 235 748), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, June 1974. 422 pp.

TABLE 27. TOTAL EMISSIONS AND PERCENT CONTRIBUTIONS TO STATE EMISSION BURDENS FROM DRY BOTTOM INDUSTRIAL BOILERS FIRING PULVERIZED BITUMINOUS COAL

State	Total annual emissions from source type (5), metric tons/yr					Total emissions from all sources (66), metric tons/yr					Percent of total emissions burden				
	Particulate	SO_x	NO_x	Hydrocarbons	CO	Particulate	SO_x	NO_x	Hydrocarbons	CO	Particulate	SO_x	NO_x	Hydrocarbons	CO
Alabama	93	1,900	1,373	23	73	1,178,642	882,730	397,068	643,410	1,885,657	<0.01	0.2	0.3	<0.1	<0.001
Georgia	1,997	5,665	669	10	32	404,573	472,418	369,817	458,010	2,036,010	0.5	1.2	0.2	<0.01	<0.01
Idaho	2,599	1,815	1,558	19	58	55,499	54,387	48,552	84,230	343,720	4.7	3.3	3.2	0.02	<0.01
Illinois	29,868	40,378	7,377	142	409	1,143,027	2,043,020	974,372	1,825,913	6,412,718	2.6	2.0	0.8	<0.01	<0.01
Indiana	1,714	20,342	6,576	106	324	784,405	2,050,541	1,371,233	600,477	2,933,780	0.2	1.0	0.5	0.2	0.01
Iowa	3,878	25,703	8,725	300	183	216,493	283,416	242,524	316,617	1,440,621	1.8	9.1	3.6	0.1	0.01
Kansas	13	275	37	1	2	348,351	86,974	233,987	309,633	1,002,375	<0.01	0.3	0.02	<0.01	<0.01
Kentucky	1,865	7,244	1,497	11	2	546,214	1,202,827	419,142	326,265	1,129,332	0.3	0.6	0.4	<0.01	<0.01
Maryland	668	17,293	6,036	57	5	494,920	420,037	265,203	295,866	1,261,804	0.1	4.1	2.3	0.02	<0.01
Massachusetts	650	380	94	6	13	96,159	636,466	334,379	440,481	1,682,218	0.7	0.06	0.03	<0.01	<0.01
Michigan	5,319	30,318	20,764	1,319	1,187	705,921	1,466,935	2,222,438	717,891	3,[illegible]43,525	0.8	2.1	0.9	0.2	0.04
Minnesota	559	655	246	4	15	266,230	391,633	311,834	410,674	1,760,749	0.2	0.2	0.08	<0.01	<0.01
Missouri	7,525	7,083	1,805	31	101	202,435	1,152,373	448,300	413,130	1,854,901	3.7	0.6	0.4	<0.01	<0.01
New York	6,864	26,477	6,327	105	352	160,044	345,979	572,451	1,262,206	4,881,922	4.3	7.7	1.1	<0.01	<0.01
North Carolina	11,352	23,003	9,613	397	691	481,018	473,020	412,599	477,238	1,734,397	2.4	4.9	2.3	0.09	0.04
Ohio	46,509	83,155	19,192	165	481	1,766,056	2,980,333	1,101,470	1,153,493	5,205,718	2.6	2.8	1.7	0.01	<0.01
Oregon	574	1,278	865	2	0	169,449	36,776	135,748	234,669	929,247	0.3	3.5	0.6	<0.01	<0.01
Pennsylvania	35,245	72,677	12,918	466	2,233	1,810,598	2,929,137	3,017,344	891,763	3,729,830	2.0	2.5	0.4	0.05	0.06
Tennessee	14,603	22,243	12,206	287	618	409,704	1,179,982	426,454	362,928	1,469,253	3.6	1.9	2.9	0.08	0.04
Utah	5,601	1,670	1,304	34	99	71,692	152,526	80,998	98,282	402,527	7.8	1.1	1.6	0.03	0.02
Virginia	40,571	46,808	16,771	330	831	477,494	447,393	329,308	369,416	1,548,031	8.5	10.5	5.1	0.09	0.05
Washington	264	328	92	5	21	161,934	272,991	187,923	344,643	1,659,117	0.2	0.1	0.05	<0.01	<0.01
West Virginia	1,482	5,831	2,299	90	193	213,715	678,348	229,598	116,155	494,214	0.7	0.9	1.0	0.08	0.04
Wisconsin	7,535	7,646	1,334	88	261	411,558	712,393	408,525	523,930	1,582,869	1.8	1.1	0.3	0.02	0.02
Wyoming	380	2,515	1,802	6	0	75,427	69,394	72,572	55,319	303,297	0.5	3.6	2.5	0.01	<0.01
U.S.	228,788	452,682	141,480	4,004	8,184	18,566,748	32,023,487	24,051,210	26,632,852	101,693,648	1.2	1.3	0.5	0.02	<0.01

AIR EMISSIONS CONTROL TECHNOLOGY

Data from the National Emissions Data System (NEDS) for this source shows that centrifugal collectors (cyclones) and electrostatic precipitators (ESP's) are the principal controls used for air emissions (5). Treating the NEDS data as a random sample of 440 dry bottom industrial boilers burning pulverized bituminous coal, it can be determined that approximately 50% of such boilers (both controlled and uncontrolled) are equipped with either cyclones or ESP's, and that together these two devices represent over 80% of the controls used. Table 28 provides a state-by-state summary of the NEDS data which shows the percentage of boilers controlled and the distribution of controls according to device type. The overall percent distribution of control devices used for this source is shown in Table 29 (5); as shown in the table, approximately 14% of the sources included in the NEDS listing use more than one particulate control device, usually a cyclone-ESP combination.

The remainder of this section discusses the current and future emission control technologies for this source type. Because little data exists in the literature for this source as defined, information on emission controls for the more general category of coal-fired industrial boilers (see Figure 3) is used. As a result, some of the efficiencies presented may have been derived from testing boilers that are not included in this specific source (e.g., cyclone boilers, wet bottom boilers, or stokers).

Particulate Controls

Almost every industrial boiler in use today is required to meet local and/or state air pollution regulations (67). Design efficiencies of commercially available equipment capable of meeting the particulate regulations are listed in Table 30 (8).

The efficiency values given in the table refer to intermediate-size coal combustion equipment including most industrial boilers (stokers, pulverizers, cyclone, etc.), small utility boilers, and large commercial/institutional units. Actual efficiencies achieved by a given control device depend on the characteristics and quantity of the particulate matter in the flue gas, which in turn depends on many factors including the operating and design

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(67) Quillman, B., and C. W. Vogelsang. Control of Particulate and SO_2 Emissions from an Industrial Boiler Plant. Combustion, 45(4):35-39, 1973.

TABLE 28. STATE-BY-STATE SUMMARY OF EMISSION CONTROLS DATA IN NEDS FOR DRY BOTTOM INDUSTRIAL BOILERS BURNING PULVERIZED BITUMINOUS COAL (5)

				Number of control devices					
State	Total number of sources	Number of controlled sources	Percent controlled	Gravity collector	Centrifugal collector	ESP	Wet scrubber	Fabric filter	Number of sources with more than one particulate control device
Alabama	1	1	100			1			
Georgia	6	6	100	1	4	2			1
Idaho	8	5	63		1		2	2	
Illinois	28	17	61	6	3	3	1	5	1
Indiana	22	11	50	2	8	1	1		1
Iowa	22	14	64	3	12			6	7
Kansas	1	1	100			1			
Kentucky	7	4	57		4	3			3
Maryland	4	4	100		3	2			2
Massachusetts	1	0	0						
Michigan	29	17	59		15	7			5
Minnesota	2	1	50		1				
Missouri	8	8	100		3	5	2		2
New York	29	19	66		18	8			7
North Carolina	42	26	62	1	19	10	1		5
Ohio	85	39	46		29	18	3	1	12
Oregon	3	3	100		3			2	1
Pennsylvania	55	32	58		26	5	2		1
Tennessee	26	17	65	3	14	5			5
Utah	6	3	50		3				
Virginia	24	21	88		16	4	3		2
Washington	1	0	0						
West Virginia	19	19	100	3	8	9		7	8
Wisconsin	9	3	33		1	2			
Wyoming	2	2	100			2			
Totals	440	273	62	19	191	88	15	23	63

Note.—Blanks indicate that no devices of the type specified appeared in the NEDS listing for that state.

characteristics of the boiler, the composition (particularly ash content) and nature of the coal, and the degree of coal pulverization (68).

Table 31 also presents particulate collection efficiencies as reported in NEDS. These values demonstrate that actual operating efficiencies are generally lower than design efficiencies.

Centrifugal Collectors--

As shown in Table 29, dry cyclones are used extensively to collect fly ash generated by this source type. In the basic cyclone collector, the entire mass of the gas stream with the entrained particulates is forced into a constrained vortex, achieved by means of fixed internal vanes, in the cylindrical portion of the cyclone. By virtue of their rotation with the carrier gas around the axis of the tube and their higher density with respect to the gas, the entrained particulates are forced toward the wall by centrifugal force and carried away by gravity and/or secondary eddies toward the outlet at the bottom of the tube. The flow vortex is reversed in the lower portion of the tube, leaving most of the entrained particulate behind. The cleaned gases then pass through the central, or exit, tube and out of the collector.

Particle size, weight and shape, and the gas flow rate affect the forces on the particles entering the collector and thus affect collection efficiency. Larger and denser particles are easier to collect; higher flow rates increase collection efficiency. For boilers burning pulverized coal, the average collection efficiency is about 90% (69).

Although centrifugal collectors are the least expensive and most reliable primary collection devices for particulates, they are no longer acceptable in many areas owing to their low collection efficiencies. In other applications, they can be used as precleaning units for precipitators, scrubbers, and fabric filters. Current design improvement efforts are directed toward increasing the collection efficiencies of centrifugal collectors through reduced reentrainment and improved gas flow distribution.

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(68) Nekervis, R. J., J. Pilcher, J. Varga, Jr., B. Gorser, and J. Hallowell. Process Modifications for Control of Particulate Emissions from Stationary Combustion, Incineration, and Metals. EPA-650/2-74-100 (PB 237 422), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, October 1974. 116 pp.

(69) Jones, A. H. Air Pollution Control for Industrial Coal-Fired Boilers. In: Power Generation: Air Pollution Monitoring and Control, K. E. Noll and W. T. Davis, eds. Ann Arbor Science Publishers, Inc., Ann Arbor, Michigan, 1976. pp. 529-542.

TABLE 29. DISTRIBUTION OF CONTROL TYPES FOR THOSE DRY BOTTOM INDUSTRIAL BOILERS BURNING PULVERIZED BITUMINOUS COAL HAVING CONTROLS (5)

Type of control device	Percent of controls in use
Gravity collectors	6
Centrifugal collectors	57
Electrostatic precipitators	26
Wet scrubber	4
Fabric filters	7
Dual controls[a]	14

Breakdown of dual controls used

Dual control system	Percent of dual controls in use
Centrifugal collector and centrifugal collector	14
Centrifugual collector and fabric filters	10
Centrifugal collector and wet scrubbers	8
Gravity collector and centrifugal collector	5
Centrifugal collector and ESP	57
ESP and ESP	2
ESP and wet scrubber	3
Gravity collector and ESP	2

[a] Two separate control devices used in series.

TABLE 30. DESIGN AND REPORTED EFFICIENCIES OF COMMERCIAL PARTICULATE CONTROLS APPLIED TO INDUSTRIAL SIZED BOILERS (5,8)

Collector type	Design efficiency, %	Efficiency as reported in NEDS, %	
		Range	Average
Centrifugal collectors	94	25 to 99.3[a]	79
Gravity collector	-[b]	25 to 85	56
Electrostatic precipitators	99.5	71.9 to 99.5	96
Fabric filters	99.5	46.5 to 99.5	91
Wet scrubbers (low pressure drop)	94	60 to 99	81
Wet scrubbers (high pressure drop)	98		

[a] Upper end of range is high and may be in error.

[b] Not reported.

Electrostatic Precipitators--

An electrostatic precipitator (ESP) separates particles and mists from gases by passing the gas stream between two electrodes across which a unidirectional, high-voltage (20 kV to 80 kV DC) potential is effected. The particles pass through this field, becoming charged and migrating to the oppositely charged electrode. Collected particles remain on the charged electrode until removed, and the gas which has thus been cleaned moves on to recovery or exhaust. Periodic vibration of the collecting electrode surface causes the dust to drop into hoppers for removal.

Very high collection efficiences can be achieved using ESP's; most new units are rated at 99% or higher. However, many precipitators operate at 0.5% to 5% below the rated efficiency because of adverse flue gas characteristics or mechanical/ electrical maintenance problems (8). Generally, collection efficiencies are reduced as particle size decreases and gas flow rate increases. The electrical resistivity of the fly ash is also important; decreased resistivity improves collection efficiency. In the temperature range characteristic of flue gases, fly ash resistivity decreases with increasing temperature and with increasing sulfur and carbon content (70).

Fabric Filters--

In fabric filters, particles in the flue gas are mechanically filtered out by tube-like cloth bags located in a baghouse (enclosing structure). Removal of the trapped particles is accomplished by shaking the bag, reversing the air flow, or rapidly expanding the bags using compressed air. Chief drawbacks of fabric filters are the high pressure drop required and the short life-span of many bag materials.

Fabric filters are the most promising technology for controlling small (submicron) particulate matter. They can be extremely efficient; removal efficiencies have been reported in the range of 99.9% (71).

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(70) Baxter, W. A. Electrostatic Precipitator Design for Western Coals. In: Power Generation: Air Pollution Monitoring and Control, K. E. Noll and W. T. Davis, eds. Ann Arbor Science Publishers, Inc., Ann Arbor, Michigan, 1976. pp. 415-425.

(71) Forester, W. S. Future Bright for Fabric Filters. Environmental Science and Technology, 8(6):508, 1974.

Wet Scrubbers--

Wet scrubbers use water or other liquids as the scrubbing agent to remove particles and absorb gaseous emissions from combustion gases. The liquid containing the pollutants is then separated from the gas stream.

There are two categories of scrubbers: low energy (pressure drop of 750 Pa to 3,700 Pa) and high energy (pressure drop of 3,700 Pa to 25,000 Pa). Numerous scrubber configurations are used for low energy units. Venturi type scrubbers are used in installations requiring high-energy collection of submicron particles. The unique shape of the Venturi offers 98% velocity head (power consumption) recovery, thereby allowing efficient introduction of fluid to meet the gas crossflow in the throat region.

Scrubbers applied to coal-fired boilers typically operate in the 2,000 Pa to 3,700 Pa pressure drop range (69). Currently, few wet scrubbers are used for this source type; such units may gain popularity if they are shown to be effective in reducing SO_x and/or NO_x emissions.

Sulfur Oxides Control

Industrial boilers producing less than 264 x 10^3 GJ/hr are not covered by federal SO_x regulations but may be subject to state standards which vary considerably. Two options are available currently for meeting SO_x emission limitations: use of low-sulfur coal, or installation of flue gas desulfurization (FDG) systems.

SO_x Control by Use of Low-Sulfur Coal--

Sulfur emissions from coal-fired boilers are directly related to the sulfur content of the coal. A decrease in sulfur content results in a corresponding reduction in emissions. Low-sulfur coal can be obtained from naturally occurring deposits or through the physical cleaning of coal high in pyritic sulfur.

Supplies of low-sulfur, high quality, eastern coal are limited. While low-sulfur western coal is available, its use in existing industrial boilers will be limited. Western coal, with its generally lower heating value and higher moisture content than Eastern coal, must be used in greater tonnage to meet a given stream output. Boilers operating near design capacity and burning alternate western coal could not meet original load requirements without extensive modification. It has been estimated that supplies of low-sulfur coal will meet only 44% of the demands in 1980 (72).

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(72) Green, R. Utilities Scrub Out SO_x. Chemical Engineering, 84(11):101-103, 1977.

Physical cleaning (beneficiation) of coal removes up to 80% of the inorganic pyritic and sulfate sulfur; however, it does not remove the organic sulfur which can account for 20% to 85% of the sulfur present (72). Beneficiation is accomplished by crushing the coal and separating the heavier pyrite-bearing particles using techniques which utilize particle density differences. This procedure is applicable to only about 17% of the coal presently mined in the United States (73). In the remaining coal, either the ratio of organic sulfur to inorganic sulfur is too high or the sulfur content is too low to permit economic handling.

SO_x Control by Use of Flue Gas Desulfurization--

Sulfur oxides are removed from flue gas by absorption and/or chemical reaction using a solid or liquid phase. Presently, about two dozen FGD processes at various stages of development are being evaluated in the United States. These processes are classified as nonregenerable or regenerable, depending on the fate of the reactive component of the absorbent. Nonregenerable processes produce a sluge consisting of fly ash, water, and sulfate/sulfite salts which must be discarded. In regenerable processes, the sulfur is recovered and converted into marketable products such as elemental sulfur, sulfuric acid, or concentrated sulfur dioxide; the absorbent is regenerated and recycled.

The nonregenerable processes, which are developed farther and used more than the regenerable processes, account for 90% (by capacity) of all FGD systems applied to industrial boilers (74, 75). Lime scrubbing, sodium alkali scrubbing and the dual alkali process represent the nonregenerable processses in commercial use on industrial boilers. Regenerable processes under construction or being planned include the Wellman-Lord and the Citrate processes. Table 31 summarizes the results of a recent survey of FGD systems applied to industrial boilers (74).

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(73) Davis, J. C. Coal Cleaning Readies for Wider Sulfur-Removal Role. Chemical Engineering, 83(5):70-74, 1976.

(74) Kaplan, N., and M. A. Maxwell. Removal of SO_2 from Industrial Waste Gas. Chemical Engineering, 84(22):127-135, 1977.

(75) Tuttle, J., A. Patkar, and N. Gregory. EPA Industrial Boiler FDG Survey: First Quarter 1978. EPA-600/7-78-052a (2PB 279 214), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, March 1978, 158 pp.

Numerous process descriptions of the various FGD systems being marketed or under development are available in the literature (8, 76-78). Descriptions of the industrial boiler SO_x scrubbers currently in use or under construction are given in Table 32. Available operating experience is also presented (70).

TABLE 31. U.S. INDUSTRIAL-BOILER SO_2 CONTROL SYSTEMS (74)

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Control system	No. of systems	Approximate total output capacity, GJ/hr	Status
Sodium alkali scrubbing	12	2,820	Operational
	2	623	Under construction
	1	72	Not operating
Dual alkali	4	396	Operational
	2	720	Under construction
	1	43	Planned
	1	36	Not operating
Lime/limestone scrubbing	1	72	Operational
Wellman-Lord	1	360	Planned
Water scrubbing	1	4	Not operating
Citrate process	1	180	Under construction
Total	27	5,326	

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(76) Choi, P. S. K., E. L. Krapp, W. E. Ballantyne, M. Y. Anastas, A. A. Putnam, D. W. Hissong, and T. J. Thomas. SO_2 Reduction in Non-Utility Combustion Source -- Technical and Economic Comparison of Alternatives. EPA-600/2-75-073 (PB 248 051), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, October 1975. 316 pp.

(77) Flue Gas Desulfurization and Sulfuric Acid Production via Magnesia Scrubbing. EPA-625/2-75-007 (PB 258 817), U.S. Environmental Protection Agency, Washington, D.C., 1975. 24 pp.

(78) Shore, D., J. J. O'Donnell, and F. K. Chan. Evaluation of R & D Investment Alternatives for SO_x Air Pollution Control Processes. EPA-650/2-74-098 (PB 238 263), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, September 1974. 288 pp.

TABLE 32. DESCRIPTIONS OF INDUSTRIAL SO_2 SCRUBBERS (75)

Scrubber type	Plant and location	Process description	Removal efficiency of SO_x	Waste disposal[a]	Operational experience
Sodium alkali	FMC (soda ash plant) Green River, WY Operational since 1976.	System consists of two FMC FMC sodium scrubbing units to remove SO_2 from the flue gas of two coal-fired boilers (200 MW). The pH is maintained at 6.5 by addition of soda ash (Na_2CO_3) liquor from the plant.	95% (800 ppm at inlet). Preceded by ESP to remove particulates.	Holding pond for evaporation of Na_2SO_3/SO_4 liquor, with no prior aeration. Landfill in future.	Successful operation. Scrubber lining corroded as a result of faulty installation. Foaming and sedimentation in scrubber occurred due to impurities in liquor.
Sodium alkali	General Motors, Chevrolet Motor Division Tonowanda, NY Operational since 1975.	System consists of four GM sodium scrubbing units equipped with venturi scrubbers on four coal-fired boilers (32 MW). The pH is maintained at 7.0 by addition of caustic soda (NaOH).	90% to 95% (1,000 ppm at inlet). 90% removal of particulates.	Fly ash and Na_2SO_3/SO_4 waste liquor dewatered and sent to sanitary landfill. Effluent discharged to waste treatment plant.	Successful operation. Major problem areas have been pH control, recycle pipe erosion, and stack lining corrosion. The pH controller was replaced and cast iron piping installed instead of stainless steel.
Sodium alkali	General Motors St. Louis, MO Operational since 1972.	System consists of two GM sodium scrubbing units operable on two or four coal-fired boilers (25 MW). The 3-stage impingement tower is followed by a Chevron mist eliminator.	90+% (2,000 ppm at inlet). Preceded by cyclone and ESP to remove particulates.	Wastewater is treated (Na_2SO_3 oxidized to Na_2SO_4; pH neutralized) and discharged to city sewer system.	Successful operation. Main problem has been stack corrosion.
Sodium alkali	General Motors, Truck and Coach Division Pontiac, MI Operational since 1976.	System consists of two GM sodium scrubbing units on two coal-fired boilers (40 MW). The pH is controlled by addition of NaOH.	Undetermined for SO_2. 85% removal of of particulates.	Neutralized scrubber effluent is pumped to clarifier and recycled. Dewatered sludge is landfilled.	Successful operation. Only problem has been flyash abrasion in pumps and piping.
Sodium alkali	General Motors, Delco Moraine Dayton, OH Operational since 1974.	System consists of two GM sodium scrubbing units on two coal-fired boilers (24 MW).	80% 85% removal of particulates.	Wastewater is treated and discharged to city sewer system. Dewatered sludge is landfilled.	Successful operation. Problem areas have been fan bearings (replaced three times) and stack corrosion.
Sodium alkali	NCR - Appleton Roaring Springs, PA Operational since 1977.	System (installed by Airpol) consists of a a venturi followed by an absorber; controls SO_2 and particulate from a coal-fired boiler (12 MW). The pH is controlled in the 5 to 7 range by addition of NaOH to the recycle tank.	80 to 85%	Wastewater is treated and discharged to city sewer system.	Some liner problems.

TABLE 32 (continued)

Scrubber type	Plant and location	Process description	Removal efficiency of SO_x	Waste disposal[a]	Operational experience
Sodium alkali	Texasgulf Granger, WY Operational since 1976.	System, designed by Swemco, controls two coal-fired boilers (65 MW). The pH is controlled by addition of sodium carbonate.	90+% Preceded by ESP to to remove particulates.	Holding pond for evaporation.	Corrosion of piping in the recirculating lines.
Sodium alkali	Sheller Globe Corp. Norfolk, VA Operational since 1975.	System is a W. W. Sly Impingjet scrubber that controls SO_2 and particulates on a coal-fired boiler (3.5 MW). The pH is controlled by addition of NaOH.	Not determined.	Recycle tank supernatant is neutralized and discharged to city sewer system. Flyash and sediment are sent to landfill.	No problems reported.
Sodium alkali	American Thread Marion, NC Operational since 1973.	System consists of two W. W. Sly scrubbers operating on two coal-fired boilers (8 MW). The pH is controlled at 6.5 by addition of dilute NaOH solution.	90% 97% removal of particulates.	Waste slurry is pumped to a clay-lined ash basin for evaporation.	Main problem has been corrosion of fans, stack, and piping. Installation of fiberglass lining has placed a strain on fans and resulted in severe vibrations.
Sodium alkali	Georgia-Pacific Paper Co. Crossett, AR Operational since 1975.	Open loop system, designed by Airpol, uses "black water" from the pulp mill as the scrubbing liquor. Installed on a coal/bark-fired boiler (100 MW).	80% (500 ppm at inlet). Preceded by cyclones for particulate control.	Wastewater is neutralized and discharged to city sewer system.	Successful operation with no major problems. Fiberglass linings fail frequently and are replaced.
Sodium alkali	Great Sourthern Paper Co. Cedar Springs, GA Operational since 1975.	Two open loop scrubbers, designed by Airpol, on two coal/bark-fired boilers (100 MW). Caustic waste stream used for pH control.	85% to 90% (1,000 ppm at inlet). 99% removal of particulates.	Wastewater is ponded and clarified water is discharged to the river.	Problems include erosion and plugging of pH probes; internal wear on pumps; and erosion in the recirculating lines.
Sodium alkali	Nekoosa Papers, Inc. Ashdown, AR Operational since 1976.	System consists of two Airpol scrubbers on a coal-fired boiler (50 MW). The pH is controlled at 5.5 to 6.0 by addition of sodium hydroxide.	90+% (600 ppm at inlet). 98% to 99% removal of particulates.	Ash slurry goes to a settling pond. Scrubber effluent is treated and discharged to the river.	Original intent was to recover Na_2SO_4 from scrubber liquor for use at the plant. This has not yet been achieved. The scrubber itself operates well; major problem has been lack of adequate pH control and resulting corrosion.

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TABLE 32 (continued)

Scrubber type	Plant and location	Process description	Removal efficiency of SO_x	Waste disposal[a]	Operational experience
Sodium alkali	Great Western Sugar Findlay, OH Operational since 1974.	Proprietary design using sodium carbonate for pH control.	Not reported.	Wastewater is treated and discharged to city sewer system.	Not reported.
Sodium alkali	Great Western Sugar Freemont, OH Under construction.	Proprietary design using sodium carbonate for pH control.	Not available.	Wastewater will be treated and discharged to city sewer system.	Not available.
Sodium alkali	Kerr-McGee Chemical Corp. Trona, CA Under construction.	System consists of two scrubbers using end liquor from soda ash (Na_2CO_3) plant on two coal-fired boilers (64 MW). The pH is maintained at 6 to 6.5 in the recirculating liquor.	98+% (estimated) Preceded by ESP for for particulate removal.	Scrubber bleed stream is clarified and sent to salt ponds.	Not available.
Lime	Armco Steel Middletown, OH Operational since 1975.	System consists of a venturi scrubber followed by an absorber module, and serves two coal-fired boilers. System was changed from recirculating to once-through because of abrasion. The pH is maintained at 6 to 6.5 by addition of a lime slurry.	Not available.	Holding pond for evaporation.	High excess air rates in the the boilers have resulted in poor performance. Abrasion in piping has been a problem. Mist eliminator failed because of creep in plastic construction material.
Limestone	Rickenbacker Air Force Base Columbus, OH Operational since 1976.	System consists of a BAHCO scrubber serving seven coal-fired boilers.	90% (average). 98% removal of particulates.	Unstabilized slurry ($CaSO_3/SO_4$) sent to holding pond.	Successful operation; problems have been of a mechanical nature, primarily with the fan.
Citrate	St. Joe Minerals Corp. Monaca, PA Under construction.	System developed by Bureau of Mines uses uses sodium citrate/citric acid solution to scrub SO_2. Control for a coal-fired boiler (60 MW).	Not available.	This regenerable system will produce elemental sulfur as a byproduct.	Not available.

TABLE 32 (continued)

Scrubber type	Plant and location	Process description	Removal efficiency of SO_x	Waste disposal[a]	Operational experience
Double alkali	Canton Textiles Canton, GA Operational since 1974.	System is an FMC venturi scrubber using a caustic plant waste stream for SO_2 removal on a coal-fired boiler (10 MW). Liquor is regenerated with lime or limestone, clarified, and then either recycled or discharged to wastewater treatment facility.	70% (1,500 ppm at at inlet). 80% to 90% removal particulates.	Treated scrubber liquor and non-fixated slurry are diposed to lined holding ponds.	No major problems after initial startup. At that time plugging and foaming occurred because of materials in the plant wastewater used for scrubbing.
Double alkali	Caterpillar Tractor Co. Joliet, IL Operational since 1974.	System consists of two Zurn scrubbers on two coal-fired boilers (18 MW). Scrubbing liquor is regenerated by addition of lime (to precipitate $CaSO_3/SO_4$) and soda ash.	90+%	Dewatered slurry is sent to landfill; effluent is recycled.	Successful operation. Filter cloth in vacuum filters lasts only 2 to 3 weeks.
Double alkali	Caterpillar Tractor Morton, IL Operational since 1978	System consists of two Zurn scrubber on two coal-fired boilers (12 MW). Scrubbing liquor is regenerated by addition of lime (to precipitate $CaSO_3/SO_4$) and soda ash.	Not available.	Dewatered slurry is sent to landfill; effluent is recycled.	No major problems since startup.
Double alkali	Caterpillar Tractor Mossville, IL Operational since 1975.	System consists of four FMC scrubbers serving four coal-fired boilers (57 MW).	90+%	Dewatered slurry is landfilled.	Major problems have been wear and erosion due to flyash in recirculating slurry and sludge.
Double alkali	Firestone Tire and Rubber Co. Pottsdown, PA Operational since 1974.	Demonstration system consists of FMC double alkali scrubber controlling slip stream from a coal-fired boiler.	90% (1,000 ppm at inlet)	Dewatered slurry is landfilled; effluent recycled.	No problems due to scaling or plugging. Downtime due to parts failure or maintenance. Some erosion encountered.
Double alkali	General Motors Parma, OH Operational since 1974.	System consists of four GM/Koch scrubbers serving four coal-fired boilers (32 MW). Scrubbing liquor is regenerated with lime and soda ash.	90%	Dewatered slurry is sent to a drying pond and then landfilled.	A number of problems have occurred since startup, primarily mechanical, but some plugging does occur.
Double alkali	Caterpillar Tractor Co. Mapleton, IL Under construction.	System will consist of three FMC scrubbers serving three coal-fired boilers (100 MW).	Not available.	Dewatered slurry will be landfilled.	Not available.
Double alkali	Caterpillar Tractor Co. East Peoria, IL Under construction.	System will consist of four FMC scrubbers serving four coal-fired boilers (100 MW).	Not available.	Dewatered slurry will be landfilled.	Not available.

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[a] Common practice is to recycle scrubber liquor; a portion is withdrawn to prevent too high a buildup of dissolved solids. This purge stream is treated before discharge.

Nitrogen Oxides Control

Current applications of NO_x controls to industrial boilers are almost nonexistent; however, such controls are expected to increase in view of impending local standards for some existing units and planned New Source Performance Standards (NSPS) for new units. Combustion modification and flue gas treatment (79) are NO_x control technologies presently in the demonstration stage; each of these is briefly described below.

NO_x Control by Combustion Modification

Current stationary source NO_x emission standards and those envisioned for the near future are based on combustion modification techniques. In the temperature range used in dry bottom boilers, thermal formation of NO_x from atomspheric nitrogen does not make a large contribution to total NO_x emissions. Therefore, the most effective combustion modification techniques focus on reducing the oxidation of fuel nitrogen. The major factors influencing the formation of NO_x from fuel nitrogen are oxygen concentration, fuel nitrogen content, temperature, and residence time (41-45, 80, 81).

Reduction of NO_x from fuel bound nitrogen can be accomplished by providing a fuel rich environment for combustion to occur. A simple model of the nitrogen to NO_x conversion process was developed, based on experimental data in which 1) the conversion efficiency is inversely proportional to the weight fraction of nitrogen in the fuel and 2) the conversion efficiency is linearly proportional to the local air-fuel ratio, with zero NO_x occurring when there is just sufficient oxygen present to oxidize the fuel carbon to carbon monoxide and the fuel hydrogen to water (82, 83).

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(79) Mason, H. B., and L. R. Waterland. Environmental Assessment of Stationary Source NO_x Combustion Modification Technologies. In: Proceedings of the Second Stationary Source Combustion Symposium; Volume I: Small Industrial, Commercial, and Residential Systems. EPA-600/7-77-073a (PB 270 923), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, July 1977. pp. 37-82.

(80) Armento, W. J., and W. L. Sage. Effect of Design and Operation Variables on NO_x Formation in Coal-Fired Furnaces: Status Report. In: Air - II. Control of NO_x and SO_x Emissions, AIChE Symposium Series No. 148, 71:63-70, 1975.

(81) England, C. and J. Houseman. NO_x Reduction Techniques in Pulverized Coal Combustion. In: Proceedings, Coal Combustion Seminar. EPA-650/2-73-021 (PB 224 210), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, September 1973. pp. 173-190.

Two successful approaches have been used to achieve fuel rich combustion, thereby lowering NO_x emissions from coal-fired boilers. These are 1) the reduction of the amount of excess air fired and 2) staged combustion. Excess air refers to air added to a furnace in excess of that required for stoichiometric combustion. Various studies on industrial coal-fired boilers have shown that reduction in the amount of excess air being fired is the best method for changing primary flame zone conditions considering such factors as ease of implementation, emission reduction, and effect on boiler efficiency (51, 53, 80). NO_x emissions decreased an average to 50 ppm for each 1% reduction in excess air; a total reduction of 38% from the baseline NO_x emissions was found to be attainable. Low excess-air operation improves boiler efficiency and does not increase particulate emissions as do some other modifications.

Staged combustion describes a combustion modification technique in which the lower level (or upstream) burners in a furnace are fired with a fuel rich air/fuel mixture. The remainder of the combustion air necessary to achieve complete combustion is then added via the upper level (or downstream) burners. Combustion thus occurs in two distinct stages, the first one being a fuel rich stage where very little NO_x can form from the fuel nitrogen. The second stage attains a stoichiometric fuel/air ratio, but the flame temperature and residence time are conducive to lower levels of NO_x production. It has also been postulated that, in the fuel rich region, fuel nitrogen is initially converted to NO. However, in the presence of unreacted carbon and hydrogen, NO is reduced to stable nitrogen compounds such as N_2 (83). Staged combustion has been shown to yield substantially lower NO_x levels (50% decrease or more from baseline conditions, achieving below 200 ppm NO_x in the exit gas concentration). However, fuel rich operation may create problems of combustion instability and boiler corrosion, if carried out to excessive levels (40% or more of the combustion air diverted to the second stage) (83).

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(82) Dykema, O. W. Analysis of Test Data for NO_x Control in Coal-Fired Utility Boilers. EPA-600/2-76-274 (PB 261 066), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, October 1976. 100 pp.

(83) Dykema, O. W. Combustion Modification Effects on NO_x Emissions from Gas-, Oil-, and Coal-Fired Utility Boilers. EPA-600/2-78-217 (PB 289 898). U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, December 1978. 97 pp.

NO_x Control by Flue Gas Treatment--

Should standards be promulgated that are more stringent than those predicted, flue gas treatment may be required for NO_x emission reduction. Hence, experimental flue gas treatment projects are progressing toward full-scale demonstration of highly efficient control technology for NO_x and NO_x/SO_x emissions. These technologies, imported from Japan, are classified as wet or dry processes.

Dry flue gas treatment processes being developed include the following (84): 1) selective catalytic reduction, 2) selective noncatalytic reduction, 3) adsorption, 4) nonselective catalytic reduction, 5) catalytic decomposition, and 6) electron beam radiation. Of these, only selective catalytic reduction has achieved notable success in treating flue gas and progressed to the point of being commercially applied (84). Selective catalytic reduction is based on the reduction of NO_x compounds to N_2 by reaction with ammonia. Two variations of selective catalytic reduction are capable of removing both SO_x (∿90% efficient) and NO_x (70% to 90% efficient). The other dry processes are much less attractive at present due to their low NO_x removal efficiencies, nonapplicability to combustion sources, or early stage of development.

Wet flue gas treatment processes under development include the following (84): 1) oxidation-absorption, 2) absorption-oxidation, 3) oxidation-absorption-reduction, and 4) absorption-reduction. The first two processes listed are generally used only for NO_x control. In oxidation-absorption, relatively insoluble nitrogen oxide (NO) is oxidized in the gas phase to nitrogen dioxide (NO_2) which is absorbed into the liquid phase. In absorption-oxidation, NO is absorbed directly into the liquid phase and then oxidized. The last two processes listed above are designed to remove SO_x and NO_x; they are basically modifications of existing flue gas desulfurization processes. Due to their complexity, limited applicability, and water pollution problems, wet processes can not compete economically with the dry selective catalytic reduction process.

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(84) Mobley, J. D., and R. D. Stern. Status of Flue Gas Treatment Technology for Control of NO_x and Simultaneous Control of SO_x and NO_x. In: Proceedings of the Second Stationary Source Combustion Symposium; Volume III: Stationary Engine, Industrial Process Combustion Systems, and Advanced Processes. EPA-600/7-77-073c (PB 271 757), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, July 1977. pp. 299-251.

SECTION 5

WASTEWATER EFFLUENTS AND CONTROL TECHNOLOGY

SOURCES AND CHARACTERISTICS

Water usage in an industrial steam generating facility is complex and results in a number of wastewater effluents. Most of the required water is used for steam generation, cooling, equipment cleaning, and ash transport. Effluents linked with these uses contain: 1) ash and other coal combustion products; 2) chemicals added on site as biocides, corrosion inhibitors, cleaning agents, etc.; and, 3) water treatment wastes containing treatment chemicals and the pollutants present in the water supply. Total suspended solids (TSS), iron, copper, hardness, and sulfate are the principal pollutants found in coal-fired boiler effluents (1).

Wastewater quantities and, to a lesser extent, wastewater qualities associated with the operation of industrial coal-fired boilers vary with the operating practices employed. The major factors responsible for this variation are listed below:

- Cooling water for steam condensation may be used once and discharged, recirculated, or not used at all.
- Ash may be handled dry, or water slurried and sent to ash ponds.
- Depending on the quality of the water supply, a number of water treatment processes are available for preparing boiler feed water; each process generates different quantities and qualities of wastewater.
- Numerous chemical additives (shown in Table 33) containing a wide variety of active ingredients are available for use as oxygen scavengers, scale and corrosion inhibitors, biocides, water treatment chemicals, dispersing agents, cleaning agents, and for pH control (19).

Table 34 summarizes various boiler wastewater effluents and the major pollutants and pollutant parameters applicable to each stream (19). A brief description of each waste stream is presented in the following paragraphs. Because very little information exists in the literature describing water usage or effluents specific to this specific source type, the bulk of the information presented was drawn from references describing effluents from coal-fired utility boilers.

TABLE 33. CHEMICAL ADDITIVES USED IN STEAM PLANTS FOR VARIOUS APPLICATION (19)

Use	Chemical
Coagulant in clarification water treatment	Aluminum sulfate Sodium aluminate Ferrous sulfate Ferric chloride Calcium carbonate
Regeneration of ion exchange water treatment	Sulfuric acid Caustic soda Hydrochloric acid Common salt Soda ash Ammonium hydroxide
Lime soda softening water treatment	Soda ash Lime Activated magnesia Ferric salts Dolomitic lime
Corrosion inhibition or scale prevention in boilers	Disodium phosphate Trisodium phosphate Sodium nitrate
pH control in boilers	Ammonia Cyclohexylamine
Sludge conditioning	Tannins Lignins Chelates such as ethylenediaminetetraacetic acid, nitrilotriacetic acid
Oxygen scavengers in boilers	Hydrazine Morphaline
Boiler cleaning	Hydrocloric acid Citric acid Formic acid Hydroxyacetic acid Potassium bromate Phosphates Thiourea Hydrazine Ammonium hydroxide Sodium hydroxide Sodium carbonate Nitrates
Regenerants of ion exchange for condensate treatment	Caustic soda Sulfuric acid
Corrosion inhibition or scale prevention in cooling towers	Organic phosphates Sodium phosphate Chromates Zinc salts Synthetic organics
Biocides in cooling towers	Chlorine Hydrochlorous acid Sodium hypochlorite Calcium hypochlorite Organic chromates Organic zinc compounds Chlorophenates Triocyanates Organic sulfurs
pH control in cooling towers	Sulfuric acid Hydrochloric acid
Dispersing agents in cooling towers	Lignins Tannins Polyacrylonitrile Polyacrylamide Polyacrylic acids Polyacrylic acid salts
Biocides in condenser cooling water systems	Chlorine Hypochlorites
Additives to house service water systems	Chlorine Chromates Caustic soda Borates Nitrates
Numerous uses	Numerous proprietary chemicals

TABLE 34. POLLUTANTS AND POLLUTANT PARAMETERS ASSOCIATED WITH VARIOUS BOILER WASTEWATER EFFLUENTS (19)

	Condenser cooling systems		Water treatment processes				Chemical cleaning						
Parameter	Once-through	Recircu-lating	Clarifi-cation wastes	Ion-exchange wastes	Evaporator blowdown	Boiler blowdown	Boiler tubes	Air preheater	Boiler fireside	Ash pond overflow	Coal pile drainage	Floor drains	Air pollution devices SO_2 removal
Alkalinity	X	X	X	X	X	X	X	X	X	X			X
BOD[a]		X	X	X	X	X	X	X		X		X	X
COD[b]		X	X	X	X	X	X	X	X	X		X	
TS[c]	X	X	X	X	X	X	X	X	X	X	X	X	X
TDS[d]	X	X	X	X	X	X	X	X	X	X	X	X	X
TSS[e]		X	X	X	X	X	X	X	X	X	X	X	X
Ammonia		X	X	X	X	X	X	X	X	X	X		
Nitrate		X	X	X	X	X	X			X	X		
Phosphorous		X	X	X	X	X	X			X	X		X
Turbidity		X	X		X	X	X	X	X	X	X	X	X
Acidity							X	X	X	X	X	X	X
Hardness		X	X	X	X	X	X			X		X	X
Sulfate		X	X	X	X	X	X	X	X	X	X	X	X
Sulfite								X	X	X		X	X
Bromide							X						
Chloride		X	X		X	X	X	X	X	X	X		
Fluoride		X	X	X			X			X			
Aluminum		X	X		X	X	X		X	X	X		X
Boron													
Chromium		X	X	X	X	X	X	X	X	X	X		
Copper	X	X	X	X	X	X	X	X	X	X	X		
Iron		X	X	X	X	X	X	X	X	X	X		X
Lead										X	X	X	
Magnesium		X	X	X	X	X	X	X	X	X	X	X	X
Mercury				X	X		X			X	X		
Nickel		X	X	X	X	X	X	X	X	X	X		
Selenium							X			X	X		
Vanadium									X	X			X
Zinc		X	X	X	X	X	X			X	X		
Oil and grease				X			X			X		X	X
Phenols		X	X		X					X	X		
Surfactants					X		X			X		X	
Algicides	X	X											
Chlorine	X	X											
Manganese		X		X	X	X	X		X	X	X		X

[a] BOD = biochemical oxygen demand.

[b] COD = chemical oxygen demand.

[c] TS = total solids.

[d] TDS = total dissolved solids.

[e] TSS = total suspended solids.

Engineering judgment was exercised in determining the information pertinent to this source type.

Waste Streams from Cooling Water

Because the relatively small average size of industrial boilers (as compared to utility boilers) precludes the economical production of electricity, it is assumed that most such boilers produce low-grade steam for process and space heating, and that the steam condenses as it is used, thus allowing it to be returned directly to the boiler as feedwater. However, industrial units that produce high-temperature, high-pressure steam for electricity generation or other use must use cooling water to condense the spent steam for reuse in the boiler to recover the heat and to minimize the cost of meeting feedwater quality requirements. Two types of cooling systems are commonly used: once through and recirculating.

Once-through cooling systems use cooling water only one time and then discharge it. Because of the large volume of water used, treatment of the influent is minimized, and the effluent is not usually treated prior to discharge. Treatment of influent water for once-through cooling usually entails intermittent doses of a biocide such as chlorine or a hypochlorite. The frequency and duration of biocide treatments vary from plant to plant; they may be applied from once per day up to as many as ten times per day, and the duration of treatment varies between 5 minutes and 2 hours resulting in residual chlorine concentrations in the range of 0.1 g/m^3 to 1 g/m^3 (19). In addition to any chemicals added to the system, the cooling-water discharge will contain particles resulting from corrosion and erosion of the condenser tubes.

If the steam generating plant is not located near a large body of water, a once-through cooling system is impractical, and a recirculating system must be installed to minimize water costs and discharges. Recirculating systems discharge their waste heat through evaporation of some of the recirculating water in a cooling tower or pond. During evaporation, water vapor is removed and some entrainment of droplets in the air draft (drift) occurs; hence, the salts dissolved in the cooling water become more concentrated. To limit the concentrations of dissolved solids and to prevent their deposition on heat transfer surfaces, some water must be removed as blowdown. The rate of blowdown depends on the quality of the make-up water and the permissible concentration factor for a particular system. Unless limited by a specific discharge permit, the concentration factor is based on that required to protect plant equipment from scaling, fouling, corrosion, or excessive deposits. Blowdown rates range from 0.1% of the circulating water flow for high-quality, make-up water to as much as 5.0% for brackish water (85). Pollutants found in cooling water blowdown consist of a concentration of the species found in the water source, 2) air pollutants absorbed or entrained in the cooling water while in the tower, which acts as a wet scrubber for the ambient air, and 3) chemicals added for various purposes. Condenser materials are generally chosen to resist corrosion; thus special chemicals for corrosion control are not required unless the influent is high in chlorides.

Waste Streams from Water Treatment Processes

Because all water supplies contain some suspended solids and dissolved chemical salts, water intended for boiler use must be treated prior to use. Treatment processes include clarification, softening, ion exchange, and evaporation.

In the clarification process, used in the treatment of surface waters, suspended solids (turbidity) are removed through an agglomeration and settling process followed by filtration. The waste streams produced consist of a sludge and filter backwash water. The wastewater loading and the concentration of pollutants in the filter wash are both low; hence, this stream can be returned to the start of the process thus eliminating the generation of wastewater.

In the softening process, ions causing hardness are precipitated and removed as a sludge; no wastewater stream is produced. The sludges resulting from softening and clarification treatments will be discussed in Section 6 which covers solid waste control technology.

In the ion-exchange process, resins selectively remove cations and anions from feed water and replace them with hydrogen and hydroxyl ions. When the exchange capacity of a resin has been met, the resin must be regenerated resulting in the production of wastewater. Regeneration is a three-stage process consisting of a backwash to remove solids from the bed, a chemical contact step that releases the impurities from the resin, and a rinse to remove the impurities and regenerating chemicals. The chemical characteristics of the wastewater produced depend on the type of service and the influent water quality. However, such wastewater generally contains suspended solids, regenerants (usually sulfuric acid and sodium hydroxide), and the cation and anion impurities of which the most common are calcium, magnesium, potassium, sodium, sulfate, chloride, nitrate, phosphate, bicarbonate, carbonate, hydroxide and silica (in the form of $HSiO_3^-$) (19). The volume of wastewater produced depends on the size and design of the ion-exchange unit. Typically, the bed is washed for 10 min to 15 min at a flow rate of 3.4×10^{-3} m^3/s to 4.1×10^{-3} m^3/s per square meter. The cation resins are then contacted for approximately 30 min by passing the regenerant, containing two to four times the stoichiometric exchange capacity of the resin, through the bed at a controlled rate. Approximately 8 m^3 of water per cubic meter of resin is used to rinse the bed after regeneration of the cation resin. The anion resin is contacted for approximately 90 min with sodium hydroxide at a concentration of about 4% followed by a rinse of about 10 m^3 of water per cubic meter of resin (19). The frequency of regeneration depends on the influent water quality and the bed volume.

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(85) Assessment of the Costs and Capabilities of Water Pollution Control Technology for the Steam Electric Power Industry. NCWQ 75/86 (PB 251 372), National Commission on Water Quality, Washington, D.C., March 1976. 1164 pp.

In the evaporation process, used occasionally for boiler water treatment, feed water is purified using vaporization followed by external condensation and collection. During the evaporation process, a blowdown stream is maintained to prevent dissolved solids from scaling the heat transfer surfaces. The blowdown is similar in composition to that of influent water except that the impurity concentration is several times as large and the pH value is between 9 and 11 owing to the decomposition of bicarbonate ions into carbon dioxide, which comes off with water vapor, and carbonate ions.

Waste Streams from Boiler Blowdown

In addition to feedwater treatment, internal treatment of boiler waters is performed to prevent scale formation, to precipitate dissolved solids as a sludge, and to maintain the sludge in a fluid state for removal as blowdown. Blowdown, the controlled discharge of a portion of the boiler water, can be either continuous or intermittent. The quantity of blowdown wastewater varies up to 0.02 m^3 per 450 kg of steam generated (19).

Boiler blowdown characteristics vary with the quality of the feedwater and the chemicals used for internal treatment. Some of the chemicals used for scale prevention, corrosion inhibition, pH control, and oxygen scavenging are included in Table 33 (shown earlier). Generally, blowdown is an alkaline waste with a pH value of 9.5 to 11.

Blowdown from medium-pressure boilers has a total dissolved solds (TDS) concentration in the range of 100 g/m^3 to 500 g/m^3, while that from high-pressure boilers is in the range of 10 g/m^3 to 100 g/m^3. If phosphate treatment is used for scale or corrosion control, the waste will contain from 5 g/m^3 to 50 g/m^3 of phosphate and from 10 g/m^3 to 100 g/m^3 of hydroxide alkalinity. Blowdown from boilers in which hydrazine is used for oxygen scavenging contains up to 2 g/m^3 of ammonia (19).

Waste Streams from Equipment Cleaning

Periodically, boiler equipment must be removed from service and cleaned to maintain the heat transfer surfaces and other miscellaneous parts. Because each cleaning operation is tailored to the needs of particular equipment, the major operations involved are briefly reviewed on an individual basis in the following paragraphs.

Water Side Boiler Cleaning--

Because of differences in boiler scale composition, no set process exists for the internal cleaning of boiler tubes. Normally, the cleaning chemicals and procedure are based on the analysis of a boiler-scale sample. The nature of the resultant wastewater depends on the cleaning agents used, but it may contain alkalinity, organic compounds, phosphates, ammonium compounds, and scale components such as copper, iron and hardness. The frequency of boiler-tube cleaning varies considerably. In one study, the average time between cleanings was thirty months with a standard deviation of eighteen months, and its range was one cleaning every seven months to one cleaning every 100 months (19).

Boiler Fireside Cleaning--

Boiler tube exteriors are cleaned to remove ash and corrosion products. Cleaning may be accomplished using a high-pressure hose or chemicals such as soda ash or other alkaline materials to enhance the cleaning action. The waste stream may show high values for pH and hardness, and will contain suspended solids and some metals.

Condensor Cleaning--

Although the steam side of a condenser rarely requires cleaning, inhibited HCl is usually used for water side cleaning.

Air Preheater Cleaning--

Preheaters are generally cleaned in a manner similar to that used in boiler firesides. Soda ash and phosphates or detergents may be added to the high-pressure water stream. Depending on the sulfur content of the fuel, effluents are more or less acidic in nature. Waste stream constituents include fly ash, soot, rust, magnesium salts, and metallic ions (copper, iron, nickel, and chromium are usually prevalent). Preheater cleaning is performed on the average about once each month, although the frequence range varies between four and 180 times per year.

Other Equipment Cleaning--

Miscellaneous equipment also requires cleaning; this includes feedwater heaters, stacks, cooling-tower basins, air-compressor coolers, and other units. The cleaning processes, chemicals, and waste-stream characteristics are similar to those described above.

Waste Streams from Ash Handling and Ash Pond Wastewaters

Bottom ash and fly ash may be handled and transported on site using wet (sluicing) or dry (pneumatic) methods depending on the ash volume, type of collection system (i.e., wet scrubbers or ESP), availability of land, cost of water, and other factors. While no data is available on the percent usage of the wet or dry methods for the specific source type being studied, one report assumes that boilers with design capacities less than 530 GJ/hr handle their ash using a dry method (1).

Handling and transport water usage ranges from 5 to 17 m^3/metric ton of ash conveyed for fly ash, and from 10 to 170 m^3/metric ton of ash conveyed for bottom ash. Ash pond discharge rates for the utility sector, which should approximate those for industry, vary from approximately 0.005 m^3/s per million metric tons of coal burned per year to approximately 0.8 m^3/s per million metric tons of coal burned per year, with the median value being approximately 0.2 m^3/s per million metric tons of coal burned per year (19). Pollutants in the discharge consist of coal ash and its soluble components.

Waste Streams from Wet Scrubber Effluents

Wet scrubbers for air pollution control use water to absorb and remove fly ash and/or sulfur oxides from flue gas. The effluent water from particulate control scrubbers is similar to ash transport water and is often reused after solids separation to minimize erosion. Sulfur oxide scrubbers generally use an aqueous stream of lime which reacts with SO_x to form calcium sulfite and calcium sulfate, both of which precipitate. The effluent stream is usually recycled to the scrubber after removal of the precipitate as a sludge.

Waste Streams from Rainfall Runoff

Runoff from coal-storage piles contains mineral acids, dissolved solids, iron, sulfate, aluminum, copper, zinc, and manganese. Though potentially hazardous, no further assessment of rainfall runoff is included in this report because that source has been assessed (86).

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(86) Wachter, R. A., and T. R. Blackwood. Source Assessment: Water Pollutants from Coal Storage Areas. EPA-600/2-78-004m (PB 285 420), U.S. Environmental Protection Agency, Cincinnati, Ohio, May 1978. 121 pp.

Other Waste Streams

A number of minor miscellaneous waste streams may be present at a given industrial steam plant; these include sanitary wastes, floor drains, and laboratory drains. Because such sources usually feed into a sanitary sewer system, they will not be covered in this assessment report.

EFFLUENT DATA

The literature related to industrial boilers contains no data that characterize the effluents from this specific source type in sufficient detail to permit the calculation of effluent factors or the full description of water usage and wastewater handling practices. Therefore, the effluent data presented are derived totally from the field sampling effort conducted as part of this program (see Appendix C).

Description of Waste Streams Sampled

There were five wastewater streams related to the operation of the boiler at the site sampled. These streams consisted of 1) a continuous boiler blowdown, 2) wastes resulting from the regeneration of an ion-exchange bed used in feedwater treatment, 3) cooling water for the induced-draft fan bearings, 4) wash water from cleaning the steam used to operate the pneumatic ash transport system, and 5) wastewater from equipment cleaning operations. Equipment cleaning wastes were not sampled because most cleaning operations are conducted only once per year.

Water Quality Parameters and Elemental Concentrations of Waste Streams Sampled

The sampled waste streams, which exclude condenser cooling water and ash sluicing water (which are major effluents in utility boilers), and the water and effluent practices employed (e.g., the use of municipal drinking water supplies, and the discharge to a municipal sewer system) are assumed to be typical of boilers in the source type studied. Measured water quality parameters and elemental concentrations are shown in Tables 35 and 36, respectively, for the various wastewaters. An analysis of the water supply is also shown in each table for comparison.

Effluent Factors for Combined Wastewater Stream

Estimates of effluent flows as a function of coal consumption were derived from plant records, data supplied by equipment manufacturers, and observation of wastewater flows. These values, listed in Table 37, were used in conjunction with the data contained in Tables 35 and 36 to calculate effluent factors for the combined wastewater flow which are shown in Table 38.

TABLE 35. MEASURED VALUES FOR POLLUTANT CONCENTRATIONS AND WATER QUALITY PARAMETERS FOR WATER SOURCE AND WASTEWATER STREAMS

Water quality parameter	Units	Water source[a]	Wastewater streams			
			Boiler blowdown	Feed water treatment[b]	Fan bearing cooling water	Wash from ash transport[c]
Acidity[d]	g/m^3 as $CaCO_3$	1	–[e]	16	1	29
Alkalinity[f]	g/m^3 as $CaCO_3$	2	872	2	2	8
Ammonia	g/m^3	<0.05[g]	<0.05[g]	<0.05[g]	<0.05[g]	<0.05[g]
COD	g/m^3	13	84	3,670	12	1,360
Hardness	g/m^3 as $CaCO_3$	138	168	19,200	138	297
Nitrate	g/m^3	1.25	17.0	1.08	1.18	2.70
pH	pH units	8.04	11.18	7.40	8.00	4.69
Phenol	g/m^3	0.011	0.012	0.007	0.007	0.008
PCB	g/m^3	–[h]	–[h]	–[h]	–[h]	–[h]
POM	g/m^3	–[i]	–[i]	–[i]	–[i]	–[i]
Sulfate	g/m^3	71	1,360	109	72	199
Sulfite	g/m^3	<2.0[g]	<2.0[g]	<2.0[g]	<2.0[g]	<2.0[g]
TDS	g/m^3	276	4,210	88,400	160	601
TSS	g/m^3	2	11	82	4	7,500
Total solids (TS)[j]	g/m^3	302	4,300	86,900	238	9,750

[a] Municipal drinking water supply.

[b] Composite of backwash, regeneration, and rinse waste streams from an ion-exchange unit.

[c] Waste stream from wash of steam used to operate the pneumatic ash transport system; wastewater contains precipitator ash.

[d] Taken to pH 8.3.

[e] Not analyzed due to high pH.

[f] Taken to pH 4.5.

[g] Concentration below the given detection limit.

[h] Not detected at the detection levels shown in Table 17.

[i] Not detected at the detection levels shown in Table 17.

[j] TS is not equal to the sum of TDS and TSS because each value was determined independently.

TABLE 36. ELEMENTAL CONCENTRATIONS MEASURED IN WATER SOURCE AND WASTEWATER STREAMS (g/m³)

		Wastewater streams			
Element	Water source[a]	Boiler blowdown	Feedwater treatment[b]	Fan-bearing cooling water	Wash from ash transport[c]
Aluminum	0.0537	0.570	46.0	0.0516	127
Antimony	0.0406	0.0589	2.92	0.0312	0.587
Arsenic	<0.002[d]	0.004	<0.002[d]	<0.002[d]	2.30
Barium	0.0397	<0.0002[d]	11.14	0.0363	1.15
Beryllium	<0.005[d]	<0.005[d]	<0.005[d]	<0.005[d]	0.160
Boron	0.0612	0.911	<0.001[d]	0.0631	2.05
Cadmium	0.0039	0.0051	<0.002[d]	0.0024	0.052
Calcium	23.9	2.32	2,970	24.3	84.9
Chromium	0.0140	0.0195	1.07	0.0134	0.387
Cobalt	0.0100	0.0124	0.170	0.0072	0.469
Copper	0.0106	0.107	<0.004[d]	0.0026	2.26
Iron	0.0165	0.564	0.120	0.0111	57.0
Lead	0.0612	0.110	4.39	0.0393	0.802
Magnesium	19.4	2.32	2,180	19.4	38.9
Manganese	0.0007	0.0363	<0.0005[d]	0.0005	0.532
Mercury	<0.002[d]	<0.002[d]	<0.002[d]	<0.002[d]	<0.002[d]
Molybdenum	0.0329	0.104	2.42	0.0359	0.370
Nickel	0.111	0.147	9.92	0.0969	0.885
Phosphorus	0.205	22.3	15.7	0.217	14.4
Selenium	<0.010[d]	<0.010[d]	<0.010[d]	<0.010[d]	0.009
Silicon	3.61	51.2	9.53	3.55	50.5
Silver	0.0302	0.0375	1.74	0.0224	0.334
Sodium	23.2	827	20,240	19.2	32.0
Strontium	0.464	0.0563	72.1	0.463	5.79
Tin	0.0309	0.0416	2.38	0.0229	0.269
Titanium	0.0006	0.0162	0.01	0.0004	3.97
Vanadium	0.127	0.0347	14.1	0.128	3.63
Zinc	0.0369	0.0551	<0.001[d]	0.0070	1.01
Zirconium	<2.0[d]	<2.0[d]	<2.0[d]	<2.0[d]	<2.0[d]

[a] Municipal drinking water supply.

[b] Composite of backwash, regeneration, and rinse waste streams from an ion-exchange unit.

[c] Waste stream from wash of steam used to operate the pneumatic ash transport system; wastewater contains precipitator ash.

[d] Concentration below given detection limit.

TABLE 37. ESTIMATED DISCHARGE RATES OF WASTEWATER STREAMS

Wastewater stream	Discharge rate, m^3/kg of coal
Boiler blowdown	5.8×10^{-4}
Feedwater treatment	2.0×10^{-4}
Fan-bearing cooling water	6.2×10^{-4}
Wash from ash transport	1.2×10^{-4}
Total wastewater flow	1.52×10^{-3}

TABLE 38. EFFLUENT FACTORS FOR COMBINED WASTE STREAM[a]

Effluent species	Effluent factor, g/kg coal	Effluent species	Effluent factor, g/kg coal
Acidity (as $CaCO_3$)	7.3×10^{-3}	Elements (continued):	
Alkalinity (as $CaCO_3$)	5.1×10^{-1}	Calcium	6.2×10^{-1}
Ammonia	0	Chromium	2.8×10^{-4}
COD	9.5×10^{-1}	Cobalt	1.0×10^{-4}
Hardness (as $CaCO_3$)	4.1	Copper	3.4×10^{-4}
Nitrate	1.1×10^{-2}	Iron	7.2×10^{-3}
Phenol	1.4×10^{-2}	Lead	1.1×10^{-3}
PCB	0	Magnesium	4.5×10^{-1}
POM	0	Manganese	8.5×10^{-5}
Sulfate	8.8×10^{-1}	Mercury	3.0×10^{-6}
Sulfite	0	Molybdenum	6.1×10^{-4}
TDS	2.0×10^{1}	Nickel	2.2×10^{-3}
TSS	9.2×10^{-1}	Phosphorus	1.8×10^{-2}
Total solids (TS)	2.1×10^{1}	Selenium	1.5×10^{-5}
Elements:		Silicon	4.0×10^{-2}
Aluminum	2.5×10^{-2}	Silver	4.2×10^{-4}
Antimony	7.1×10^{-4}	Sodium	4.5
Arsenic	2.8×10^{-4}	Strontium	1.5×10^{-2}
Barium	2.4×10^{-3}	Tin	5.5×10^{-4}
Beryllium	2.6×10^{-5}	Titanium	4.9×10^{-4}
Boron	8.1×10^{-4}	Vanadium	3.3×10^{-3}
Cadmium	1.1×10^{-5}	Zinc	1.6×10^{-4}
		Zirconium	3.0×10^{-3}

[a] Includes boiler blowdown, fan-bearing cooling water, water wash of steam used to operate pneumatic ash transport system, and waste stream from regeneration of feedwater treatment ion-exchange unit.

POTENTIAL ENVIRONMENTAL EFFECTS

Industrial wastes discharged to a river or lake can have a detrimental effect on aquatic life and on other animals, including man, that use the water for recreational purposes (fishing, swimming, etc.) or for drinking. Information on the environmental effects and eventual fate of most pollutant species is readily available in the literature (87, 88).

The potential for environmental damage resulting from the discharge of effluents from the operation of pulverized bituminous coal-fired dry bottom industrial boilers is evaluated in a manner analogous to that used to evaluate the effects from air emissions. An average source is defined, and pollutant concentrations are determined for the effluent after dispersion into an average river at minimum flow. The pollutant concentrations are then compared to water quality criteria.

Average Source

The average source, as defined in Section 4, consists of a boiler with a design capacity of 222 GJ/hr. The wastewater streams from the operation of this boiler are assumed to be the same as those of the boiler sampled. This is a reasonable assumption for boilers in this size range. Major deviations should be encountered only for the largest boilers in this source type which may have discharges of ash sluicing water and/or once-through condensor cooling water or recirculating cooling water blowdown. Discharges from these large units should closely approximate those from utility sources.

The receiving water for discharges from the average source consists of a river with an average flow rate of 725 m^3/s and a minimum flow rate of 267 m^3/s. These values are averages for the rivers flowing through or near cities in which the boilers in this source type are located according to the NEDS listing. The rivers and flow rates used in these calculations are listed in Appendix B (89-115)

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(87) Klein, L. River Pollution II: Causes and Effects. Butterworth and Co., Limited, London, England, 1962. 456 pp.

(88) Quality Criteria for Water. EPA-440/9-76-023 (PB 263 943), U.S. Environmental Protection Agency, Washington, D.C., July 1976. 501 pp.

(89) Water Resources Data for Alabama, Water Year 1975. USGS/WRD/HD-76/003 (PB 251 854), U.S. Geological Survey, Water Resources Division, University, Alabama, January 1976. 391 pp.

(continued)

(continued)

(90) Water Resources Data for Georgia, Water Year 1975. USGS/WRD/HD-76/006 (PB 251 856), U.S. Geological Survey, Water Resources Division, Dorsville, Georgia, February 1976. 378 pp.

(91) Water Resources Data for Idaho, Water Year 1975. USGS/WRD/HD-76/034 (PB 263 998), U.S. Geological Survey, Water Resources Division, Boise, Idaho, July 1976. 698 pp.

(92) Water Resources Data for Illinois, Water Year 1975. USGS/WRD/HD-76/013 (PB 254 434), U.S. Geological Survey, Water Resources Division, Champaign, Illinois, April 1976. 408 pp.

(93) Water Resources Data for Indiana, Water Year 1975. USGS/WRD/HD-76/010 (PB 251 859), U.S. Geological Survey, Water Resources Division, Indianapolis, Indiana, March 1976. 368 pp.

(94) Water Resources Data for Iowa, Water Year 1975. USGS/WRD/HD-76/009 (PB 251 858), U.S. Geological Survey, Water Resources Division, Iowa City, Iowa, February 1976. 303 pp.

(95) Water Resources Data for Kansas, Water Year 1975. USGS/WRD/HD-76/008 (PB 251 857), U.S. Geological Survey, Water Resources Division, Lawrence, Kansas, February 1976. 401 pp.

(96) Water Resources Data for Kentucky, Water Year 1975. USGS/WRD/HD-76/002 (PB 251 853), U.S. Geological Survey, Water Resources Division, Louisville, Kentucky, January 1976. 348 pp.

(97) Water Resources Data for Massachusetts, Water Year 1975. USGS/WRD/HD-76/056 (PB 262 801), U.S. Geological Survey, Water Resources Division, Boston, Massachusetts, December 1976. 296 pp.

(98) Water Resources Data for Michigan, Water Year 1975. USGS/WRD/HD-76/037 (PB 262 807), U.S. Geological Survey, Water Resources Division, Okemos, Michigan, August 1976. 579 pp.

(99) Water Resources Data for Minnesota, Water Year 1975. USGS/WRD/HD-76/039 (PB 259 952), U.S. Geological Survey, Water Resources Division, St. Paul, Minnesota, August 1976. 523 pp.

(100) Water Resources Data for Missouri, Water Year 1975. USGS/WRD/HD-76/031 (PB 256 765), U.S. Geological Survey, Water Resources Division, Rolla, Missouri, August 1976. 378 pp.

(101) Water Resources Data for New York, Water Year 1975. USGS/WRD/HD-76/029 (PB 256 669), U.S. Geological Survey, Water Resources Division, Albany, New York, June 1976. 755 pp.

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(102) Water Resources Data for North Carolina, Water Year 1975. USGS/WRD/HD-76/011 (PB 251 860), U.S. Geological Survey, Water Resources Division, Raleight, North Carolina, March 1976. 441 pp.

(103) Water Resources for Ohio, Water Year 1975; Volume 1, Ohio River Basin. USGS/WRD/HD-76/041 (PB 261 782), U.S. Geological Survey, Water Resources Division, Columbus, Ohio, 1975. 555 pp.

(104) Water Resources Data for Ohio, Water Year 1975; Volume 2, St. Lawrence River Basin. USGS/WRD/HD-76/042 (PB 261 783), U.S. Geological Survey, Water Resources Division, Columbus, Ohio, 1975. 249 pp.

(105) Water Reosurces Data for Oregon, Water Year 1975. USGS/WRD/HD-76/017 (PB 257 153), U.S. Geological Survey, Water Resources Division, Portland, Oregon. May 1976. 607 pp.

(106) Water Resources Data for Pennsylvania, Water Year 1975; Volume 1, Delaware River Basin. USGS/WRD/HD-76/047 (PB 261 436), U.S. Geological Survey, Water Resources Division, Harrisburg, Pennsylvania, October 1976. 399 pp.

(107) Water Resources Data for Pennsylvania, Water Year 1975; Volume 2, Susquehanna and Potomac River Basins. USGS/WRD/HD-76/048 (PB 261 437), U.S. Geological Survey, Water Resources Division, Harrisburg, Pennsylvania, October 1976. 374 pp.

(108) Water Resources Data for Pennsylvania, Water Year 1975; Volume 3, Ohio River and St. Lawrence River Basins. USGS/WRD/HD-76/049 (PB 261 438), U.S. Geological Survey, Water Resources Division, Harrisburg, Pennsylvania, October 1976. 209 pp.

(109) Water Resources Data for Tennessee, Water Year 1975. USGS/WRD/HD-76/005 (PB 254 462), U.S. Geological Survey, Water Resources Division, Nashville, Tennessee, March 1976. 467 pp.

(110) Water Resources Data for Utah, Water Year 1975. USGS/WRD/HD-76/028 (PB 259 783), U.S. Geological Survey, Water Resources Division, Salt Lake City, Utah, July 1976. 529 pp.

(111) Water Resources Data for Virginia, Water Year 1975. USGS/WRD/HD-76/035 (PB 259 196), U.S. Geological Survey, Water Resources Division, Richmond, Virginia, September 1976. 363 pp.

(112) Water Resources Data for Washington, Water Year 1975. USGS/WRD/HD-76/033 (PB 259 197), U.S. Geological Survey, Water Resources Division, Tacoma, Washington, August 1976. 700 pp.

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Source Severity

Effluent source severities represent a comparison of the pollutant concentrations occurring in a natural water system as a result of wastewater discharges to the water quality criteria (88) when available or to aquatic toxicity data. The effluent source severity, S_e, is defined as follows:

$$S_e = \frac{V_D\ C_D}{(V_D + V_R)F_e} \qquad (6)$$

where V_D = effluent discharge rate, m^3/s

C_D = concentration of a pollutant in the effluent g/m^3

V_R = minimum river flow rate, m^3/s

F_e = Hazard factor = water quality criterion when available

or otherwise = 0.01 LC_{50} (96 hr) for the organism with the least tolerance (where LC_{50}[96-hr] is the concentration of a chemical specie that is lethal to 50% of the test organisms in a 96-hr test period), g/m^3

A derivation and explanation of the severity term is presented in Appendix D. Hazard factors used in determining severities are listed in Table 39 together with the references from which they were derived. Effluent source severities calculated for the average source are shown in Table 40. These source severities are based on effluent factors for uncontrolled discharges although it is suspected that most discharges are treated either on site or off site before discharge into natural waters. Because very little data exist on treatment practices used and no data were found on the nature of these streams after treatment,

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(113) Water Resources Data for West Virginia, Water Year 1975. USGS/WRD/HD-76/052 (PB 262 742), U.S. Geological Survey, Water Resources Division, Charleston, West Virginia, November 1976. 299 pp.

(114) Water Resources Data for Wisconsin, Water Year 1975. USGS/WRD/HD-76/045 (PB 259 825), U.S. Geological Survey, Water Resources Division, Madison, Wisconsin, October 1976. 580 pp.

(115) Water Resources Data for Wyoming, Water Year 1975. USGS/WRD/HD-76/038 (PB 259 841), U.S. Geological Survey, Water Resources Division, Cheyenne, Wyoming, October 1976. 664 pp.

TABLE 39. EFFLUENT HAZARD FACTORS FOR WATER POLLUTANTS AND WATER QUALITY PARAMETERS

Pollutant species	Hazard factor (F_e), g/m³	Reference	Comments
Acidity	20	88	As $CaCO_3$
Alkalinity	20	88	As $CaCO_3$
Ammonia	0.02	88	
COD	-[a]		
Hardness	75 to 150	88	As $CaCO_3$
Nitrate	10	88	
pH	-[a]	88	6.5 to 9.0 is considered acceptable
Phenol	1×10^{-3}	88	
PCB	1×10^{-6}	88	
POM	0.02[b]	64, 118	-[c]
Sulfate	250	88	
Sulfite	0.3	116, 117	-[c]
TDS	250	88	
TSS	25	88	
TS	275	88	
Elements:			
Aluminum	8.33[b]	116, 117	For aluminum chloride[c]
Antimony	0.225[b]	116, 117	-[c]
Arsenic	0.050	88	
Barium	1.0	88	
Beryllium	0.011	88	
Boron	0.75	88	
Cadmium	0.010	88	
Calcium	1.6	116, 118	From LC_{50} (96-hr) Mosquito fish for CaOH or CaO[c]
Chromium	0.05	88	
Cobalt	0.008[b]	64, 116	-[c]
Copper	1.0	88	
Iron	0.3	88	
Lead	0.050	88	
Magnesium	0.518[b]	116, 117	-[c]
Manganese	0.05	88	
Mercury	0.002	88	
Molybdenum	0.281[b]	116, 117	-[c]
Nickel	0.0013	88	
Phosphorus	0.1	88	Value for phosphate phosphorus
Selenium	0.010	88	
Silicon	25[d]	88	Value for total suspended solids
Silver	0.05	88	
Sodium	250	88	
Strontium	250[d]	88	Value for total dissolved solids
Tin	0.01[b]	64, 116	Value for organic tin[c]
Titanium	0.75[b]	116, 119	Value for titanium oxide[c]
Vanadium	0.55	116, 118	From LC_{50} (96-hr) fathead minnow value for V_2O_5[c]
Zinc	5.0	88	
Zirconium	1.15	116, 118	From LC_{50} (96-hr) fathead minnow value for $ZrSO_4$ in hard water

[a] Not appropriate.

[b] Derived from toxicity data other than LC_{50} as explained in Reference 116.

[c] Hazard factor is derived in Reference 116 from toxicity data found in References 61, 117, 118, 119.

[d] No water quality criteria or toxicity data available.

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(116) Reznik, R. B., E. C. Eimutis, J. L. Delaney, S. R. Archer, J. C. Ochsner, W. R. McCurley, and T. W. Hughes. Source Assessment: Prioritization of Stationary Water Pollution Sources. EPA-600/2-78-004q (PB 285 421), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, July 1978. 137 pp.

(117) The Toxic Substances List--1974. HSM 99-73-45, National Institute for Occupational Safety and Health, Rockville, Maryland, June 1974. 904 pp.

(118) Supplement to Development Document: Hazardous Substances Regulations. Section 311 of the Federal Water Pollution Control Act as Amended 1972. EPA-440/9-75-009 (PB 258 514), U.S. Environmental Protection Agency, Washington, D.C., November 1975. 783 pp.

(119) Registry of Toxic Effects of Chemical Substances, 1975 Edition. Publication No. CDC 99-74-92, National Institute for Occupational Safety and Health, Rockville, Maryland, June 1975. 1296 pp.

it is assumed that these sources discharge directly into natural waters. This approach provides a worst case analysis based on the average minimum river flow rate. The flow rates for rivers, listed in Appendix B, vary by more than five orders of magnitude. However, considering the low severity values for most pollutants as listed in Table 40, the deviation in river flow rates will not have a significant impact on the number of severity values exceeding the evaluation criteria.

TABLE 40. EFFLUENT SOURCE SEVERITIES FOR AN AVERAGE SOURCE

Pollutant	Concentration in combined effluent (C_D), g/m³	Pollutant discharge rate for average source ($V_D \bullet C_D$), g/s	Severity (S_e)
Acidity (as $CaCO_3$)	4.8	1.5×10^{-2}	2.8×10^{-6}
Alkalinity (as $CaCO_3$)	3.4×10^{2}	1.1	2.0×10^{-4}
Ammonia	–[a]	$<5.0 \times 10^{-2}$[b]	0
Hardness (as $CaCO_3$)	2.7×10^{3}	8.4	2.9×10^{-4}
Nitrate	7.2	2.2×10^{-2}	8.4×10^{-6}
Phenol	9.2	2.9×10^{-2}	1.1×10^{-1}
PCB	–[a]	–[c]	0
POM	–[a]	–[c]	0
Sulfate	5.8×10^{2}	1.8	2.7×10^{-5}
Sulfite	–[a]	<2.0[b]	0
TDS	1.3×10^{4}	4.1×10^{1}	6.1×10^{-4}
TSS	6.1×10^{2}	1.9	2.9×10^{-4}
TS	1.4×10^{4}	4.4×10^{1}	5.9×10^{-4}
Elements:			
Aluminum	1.6×10^{1}	5.0×10^{-2}	2.2×10^{-5}
Antimony	4.7×10^{-1}	1.5×10^{-3}	2.4×10^{-5}
Arsenic	1.8×10^{-1}	5.6×10^{-4}	4.2×10^{-5}
Barium	1.6	5.0×10^{-3}	1.9×10^{-5}
Beryllium	1.7×10^{-2}	5.3×10^{-5}	1.8×10^{-5}
Boron	5.3×10^{-1}	1.7×10^{-3}	8.3×10^{-6}
Cadmium	7.2×10^{-3}	2.2×10^{-5}	8.4×10^{-6}
Calcium	4.1×10^{2}	1.3	3.0×10^{-3}
Chromium	1.8×10^{-1}	5.6×10^{-4}	4.2×10^{-5}
Cobalt	6.6×10^{-2}	2.1×10^{-4}	9.6×10^{-5}
Copper	2.2×10^{-1}	6.9×10^{-4}	2.6×10^{-6}
Iron	4.7	1.5×10^{-2}	1.8×10^{-4}
Lead	7.2×10^{-1}	2.2×10^{-3}	1.7×10^{-4}
Magnesium	3.0×10^{2}	9.4×10^{-1}	6.8×10^{-3}
Manganese	5.6×10^{-2}	1.7×10^{-4}	1.3×10^{-5}
Mercury	–[a]	$<2.0 \times 10^{-3}$[b]	0
Molybdenum	4.0×10^{-1}	1.2×10^{-3}	1.7×10^{-5}
Nickel	1.4	4.4×10^{-3}	1.3×10^{-2}
Phosphorus	1.2×10^{1}	3.7×10^{-2}	1.4×10^{-3}
Selenium	9.9×10^{-3}	3.1×10^{-5}	1.2×10^{-5}
Silicon	2.6×10^{1}	8.1×10^{-2}	1.2×10^{-5}
Silver	2.8×10^{-1}	8.7×10^{-4}	6.5×10^{-5}
Sodium	3.0×10^{3}	9.4	1.4×10^{-4}
Strontium	9.9	3.1×10^{-2}	4.6×10^{-7}
Tin	3.6×10^{-1}	1.1×10^{-3}	4.2×10^{-4}
Titanium	3.2×10^{-1}	1.0×10^{-3}	5.0×10^{-6}
Vanadium	2.2	6.9×10^{-3}	4.7×10^{-5}
Zinc	1.1×10^{-1}	3.4×10^{-4}	2.6×10^{-7}
Zirconium	–[a]	<2.0[b]	0

[a] Not detected in any wastestream.

[b] Discharge rate is based on the detection limit for this compound.

[c] Detection limits vary depending on the compound of interest, but are in the microgram per liter range.

WASTEWATER TREATMENT

Because wastewater handling practices for industrial boilers are not well defined in the literature, it is assumed that wastewater treatment practices for boilers with design capacities exceeding 530 GJ/hr parallel those for utility sources (1). Sources of the design capacity specified account for approximately 7% of the dry bottom, pulverized, coal-fired boilers in the industrial category (5). It is estimated that these boilers generate about 12×10^6 m^3 of wastewater annually from ash transport (sluicing) operations (1).

Neutralization is the principal method of wastewater treatment used for these larger boiler sources; it is followed by controlled release to a waterway to achieve a dilution of 5,000:1 to 10,000:1 (19). Depending on the space available and the nature of other wastewater streams generated at the site, a holding pond may be used to permit sedimentation; if climatic conditions are favorable, an evaporation pond may be utilized alternatively. Other options include off-site treatment and disposal by a commercial waste-disposal firm, ocean dumping, and solidification of wastes by an outside vendor for land disposal. However, these methods are costly and not often employed.

Boilers with a design capacity below 530 GJ/hr are assumed to handle their ash dry (1) and thus have a much lower, total wastewater volume. In addition, if the steam from these units is used primarily for process or space heating, no condenser or cooling water is required because the steam condenses in the system and the hot water may be returned directly to the boiler. Therefore, the primary wastewater streams are the relatively low-volume effluents from feedwater treatment, boiler blowdown, cooling water for fan bearings, steam condensate from the pneumatic ash transport system, and miscellaneous equipment cleaning. In most plants these wastes are either discharged to a municipal sewer system or sent to the plant wastewater treatment facility where they are mixed with process waste streams. In plants having their own treatment systems, the unit operations are determined by the nature of the process wastes.

SECTION 6

SOLID WASTES AND CONTROL TECHNOLOGY

SOURCES AND COMPOSITION

Coal ash generated in the furnace by combustion constitutes the major source of solid wastes from industrial boilers. GCA Corporation has estimated that 2.1 x 10^6 metric tons of ash are collected annually from this source (1). Other potential solid waste sources are the sludges created by the softening of boiler feed water using lime and soda ash, and by the operation of some SO_x scrubbers.

Coal Ash

Bituminous coal contains 4% to 15% inorganic ash. On combustion, the ash content is distributed between bottom ash and fly ash. Bottom ash consists of the heavier particles which fall to the bottom of the furnace. Such ash either accumulates on the floor of the furnace for periodic removal or is collected in a hopper fitted to the furnace bottom. The remaining ash is entrained in the combustion gas stream. The distribution between bottom ash and fly ash is a function of boiler type. Table 41 (1) presents the average distribution of bottom ash to fly ash for the defined source type and for other boiler types for comparison.

TABLE 41. DISTRIBUTION OF COAL ASH BY BOILER TYPE (1)

Boiler type	Percent distribution of bottom ash to fly ash
Pulverized dry bottom	15:85
Pulverized wet bottom	35:65
Cyclone	90:10
Stoker	65:35

Because dry bottom boilers produce primarily fly ash, it is clear that the major factor influencing the quantity of ash to be discarded is the extent of particulate control. From an analysis of NEDS data, it is estimated that 62% of the boilers in the category being studied are equipped with controls which have collection efficiencies ranging from 25% to 99+% (7).

Typical physical properties of coal ash from pulverized coal-fired plants are presented in Table 42 (120). Differences in the physical properties of bottom ash and fly ash are minor; these result from slight differences in trace metal content due to element partioning and from a higher carbon content in the fly ash.

TABLE 42. TYPICAL PHYSICAL PROPERTIES OF FLY ASH FROM PULVERIZED COAL FIRED PLANTS (120)

Constituent	Range
pH	6.5 to 4.5
Particle size range, μm	0.5 to 100
Average percent of particles passing 325-mesh sieve, (44 μm), %	60 to 90
Bulk density (compacted), kg/m^3	1,100 to 1,300
Specific gravity	2.1 to 2.6
Specific area per gram, cm^2/g	3,300 to 6,400

The specific chemical composition of a coal ash is dictated by the geology of the coal deposit and the boiler operating parameters. Coal ash is primarily an iron-aluminum silicate with additions of lime, magnesia, sulfate, sodium and potassium oxides, carbon, and traces of heavy metals. A detailed listing of the chemical constituents of coal ash, showing the average composition and the composition range is provided in Table 43 (121). Because of high temperature at which most coal ash is formed, a glassy phase is produced which can account for up to 90% of the ash structure. Other crystal phases often encountered in ash include mullite, quartz, hematite, and magnetite. The distribution of these mineral phases is shown in Table 43 (121).

Lime - Soda Ash Softening Sludge

Water destined for boiler use is treated using the lime - soda ash softening process which produces a solid sludge waste. However, the extent to which this softening process is used for the treatment of boiler feedwaters for the source type being

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(120) Ash Utilization. Bureau of Mines Information Circular IC8488, U.S. Department of the Interior, Washington, D.C., 1970. 351 pp.

(121) Hecht, N. L., and D. S. Duvall. Characterization and Utilization of Municipal and Utility Sludges and Ashes; Volume III - Utility Coal Ash. EPA-670/2-75-033c (PB 244-312), U.S. Environmental Protection Agency, Cincinnati, Ohio, May 1975. 74 pp.

TABLE 43. CHEMICAL CONSTITUENTS OF COAL ASH (121)

Constituents	Composition	
	Range, %	Average, %
Silica	20 to 60	48
Alumina	10 to 35	26
Ferric Oxide	5 to 35	15
Calcium Oxide	1 to 20	5
Magnesium Oxide	0.25 to 4	2
Titanium Dioxide	0.5 to 2.5	1
Potassium Oxide[a]	1.0 to 4.0	2
Sodium Oxide[a]	0.4 to 1.5	1
Sulfur Trioxide	0.1 to 12	2
Carbon	0.1 to 20	4
Boron	0.01 to 0.6	-[b]
Phosphorus	0.01 to 0.3	
Manganese	0.01 to 0.3	
Molybdenum	0.01 to 0.1	
Zinc	0.01 to 0.2	
Copper	0.01 to 0.1	
Mercury	0.0 to 0.02	
Uranium and thorium	0.0 to 0.1	

[a] Alkalies.

[b] Blanks indicate average not reported.

TABLE 44. MINERAL PHASES FOUND IN COAL ASH (121)

Phase	Percent
Quartz	0 to 4
Mullite	0 to 16
Magnetite	0 to 30
Hematite	1 to 8
Glass	50 to 90

studied is unknown. The softening process reduces hardness by precipitating calcium and magnesium ions; the resulting sludge containing calcium sulfate, calcium carbonate, calcium bicarbonate, magnesium hydroxide, and magnesium carbonate as principal constituents. Minor components are adsorbed onto the solids or entrained in them and may include any material present in the raw water. The quantity of sludge generated by the softening depends on the rate of boiler-water usage and the hardness of the influent water.

Flue Gas Desulfurization Sludge

Boilers equipped with nonregenerable flue gas desulfurization (FGD) processes for controlling SO_x emissions generate a solid-waste stream consisting of a gypsum-based ($CaSO_4$) sludge. Because FGD processes have been applied only recently to industrial boilers, their current usage for SO_x control is limited and includes only about 30 systems representing, at maximum, less than 1.5% of the total U.S. firing capacity of this source type as defined (1, 122). However, as SO_x emission standards become more stringent, this process may become the dominant control method. Widespread use of nonregenerable FGD processes could potentially double the volume of solid wastes generated by industrial boilers.

Waste products from FGD systems vary in composition according to the particular process used but generally contain calcium sulfate, calcium sulfite, and coal ash. Approximately 4 kg to 6 kg of sludge are produced for each kilogram of SO_x removed. Additional information on the nature of sludges produced by various processes is contained in Table 32 which was presented in Section 4.

DISPOSAL OF WASTE SOLIDS

Treatment and Disposal Practices

In large utilities, the disposal of waste solids may receive considerable attention during the early design of the power plant. In fact, the need for waste disposal may be a primary factor in locating a power plant at a specific site where impoundment of ash and sludge is possible. On the other hand, industrial plants are generally built near population centers where land is either unavailable or too expensive to justify its use as a waste disposal site. Therefore, most solid industrial wastes are hauled to remote landfill sites.

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(122) Survey of Application of Flue Gas Desulfurization Technology in the Industrial Sector. FEA/G-77/304 (PB 270 548), Federal Energy Administration, Washington, D.C., December 22, 1976. 100 pp.

Coal ash collected in an electrostatic precipitator, baghouse, bottom hopper, or other unit is moved to on-site facilities for temporary storage using water sluicing, gravity flow, or pneumatic transport. From the storage facilities, which usually consist of an ash holding pond or hopper, the ash is loaded onto trucks using dredging, pumping, or gravity flow and removed for disposal or resource recovery.

Coal ash is usually discarded in landfills. Depending on the type of ash collection devices and the on-site ash handling and storage facilities, the ash may be delivered to the disposal area either wet or dry. Generally, the ash is not treated per se prior to disposal. However, ash stored in a holding pond receives some treatment in that a portion of the soluble materials is removed thus lessening the potential leaching effects.

Sludges resulting from water softening processes can be discarded by direct discharge to rivers or sewer systems; however, these disposal methods are regulated and limited by NPDES permits and agreements with the local wastewater treatment authorities, respectively. A more acceptable disposal practice consists of either sending the sludge to a pond as it comes from the process containing about 5% solids, or sending it to a landfill site after filtering, drying or other thickening operations have been performed.

The use of ponds and landfills presently represent the major options for FGD sludge disposal. Both methods are being utilized with and without sludge fixation. Lined and unlined ponds are being used (123). In anticipation of the large FGD sludge volumes expected in the future, the government is currently evaluating the possibility of using mine and ocean disposal for these materials (124).

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(123) Jones, J. W. Environmentally Acceptable Disposal of Flue Gas Desulfurization Sludges; The EPA Research and Development Program. In: Proceedings: Symposium on Flue Gas Desulfurization--Atlanta, November 1974, Volume II. EPA-650/2-74-126-b (PB 242 573), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, December 1974. 511 pp.

(124) Lunt, R. R., C. B. Cooper, S. L. Johnson, J. E. Oberholtzer, G. R. Schimke, and W. I. Watson. An Evaluation of the Disposal of Flue Gas Desulfurization Waste in Mines and the Ocean: Initial Assessment. EPA-600/7-77-051 (PB 269 270), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, May 1977. 318 pp.

Most sludges generated in SO_x scrubbers contain calcium sulfite hemihydrate ($CaSO_3 \cdot 1/2\ H_2O$), which is reponsible for the moisture retaining character and thixotropic behavior of the sludge. Because sludges are difficult to dewater and have little or no compressive strength, they are unsuitable for landfill unless chemically treated (via fixation). Three companies currently market sludge fixation technologies (125). These processes involve treatment of sludges with various chemicals to produce a material with sufficient compressive strength for landfill use and to chemically and/or physically bind up the soluble constituents of the sludges. Table 45 indicates the differences in elemental concentrations observed for raw sludge and for leachate from fixed sludge (126).

TABLE 45. TRACE ELEMENTS PRESENT IN RAW SO_x SCRUBBER SLUDGE AND IN LEACHATE FROM SLUDGE AFTER FIXATION (126)

Constituents	Raw sludge, ppm	Leachate from conditioned sludge, ppm
Arsenic	2.2	<0.10
Cadmium	0.30	<0.10
Chlorides	2,000	64.0
Chromium (total)	2.8	<0.25
Copper	1.5	<0.10
Iron	120	<0.10
Lead	26	<0.10
Mercury	<0.10	<0.10
Nickel	3.5	<0.10
Zinc	16	<0.10
Phenol	<0.25	<0.10
Cyanide	<0.10	<0.10
Sulfate	<10,000	400

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(125) Rossoff, J., R. C. Rossi, L. J. Bornstein, and J. W. Jones. Disposal of By-Products from Non-Regenerable Flue Gas Desulfurization Systems - A Status Report. In: Proceedings: Symposium on Flue Gas Desulfurization--Atlanta, November 1974, Volume I. EPA-650/2-74-126-a (PB 242 572), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, December 1974. 661 pp.

(126) Rossoff, J., and R. C. Rossi. Disposal of By-Products from Non-Regenerable Flue Gas Desulfurization Systems: Initial Report. EPA-650/2-74-037-a (PB 237 114), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, May 1974. 318 pp.

Resource Recovery

Stimulated by the large quantities of coal ash generated annually, research efforts in resource recovery have led to the development of numerous potential applications. At the present time, however, the supply greatly exceeds the demand although there is a trend toward increased utilization (121).

Appreciable quantities of coal ash are used currently as fill material for roads and other construction projects and as a partial replacement for cement in concrete and concrete products. Ash usage in concrete is expected to increase significantly because it offers technical advantages such as improved mechanical strength and improved resistance to sulfate leaching. Applications currently considered to have the potential for utilizing large quantities of ash include various agricultural uses, land recovery, road base stabilization, structural fill, and cement and concrete products.

After dewatering and treatment, sludge from the lime - soda ash softening process can be reused as a water-softening reagent or used as agricultural lime suitable for direct application. Treatment for reuse involves calcining in a furnace, removal of magnesium hydroxide by centrifuging, or a combination of the two methods (21).

Numerous FGD sludge applications have been identified for potential commercial utilization; these include its use in mineral wool, bricks, sintered concrete products, road base materials, parking lot materials, artificial aggregate, lightweight aggregate, and aerated concrete. In addition, FGD sludge may be used directly as a soil amendment and/or for sulfur and mineral recovery, or it can be converted into gypsum. Although many potential products are anticipated, some of which may be superior to those currently used, several factors exist which could inhibit large-scale sludge usage including its highly variable chemical and physical properties, substantial transportation costs (due to rate structures favoring virgin materials), and dewatering requirements.

In Japan, where FGD systems receive widespread use, most scrubber sludge is converted into gypsum for reuse in wallboard production or as a cement-setting retardant. Unfortunately, the presence of appreciable quantities of fly ash reduces the market value of wallborad produced in this manner. Because oil is the major combustion fuel in Japan, fly ash is not a problem; however, for coal-fired sources, fly ash removal ahead of the SO_x scrubber would be necessary in order to produce a marketable-grade gypsum. Gypsum production may be advantageous in any event because it can be readily dewatered to form a more stable landfill medium, and the volume of material for disposal is thus reduced. Conversion of scrubber sludge to gypsum would also eliminate the chemical oxygen demand exerted by the calcium sulfite.

POTENTIAL ENVIRONMENTAL EFFECTS

For this study, the hazard potential of the solid wastes generated by industrial boilers is assessed by considering that portion of the waste which eventually reaches the open environment as water pollution or air pollution. Water pollution from solid wastes is the result of leaching of pollutants at disposal sites by runoff to groundwater or surface waters. Air emissions result from handling operations, transportation to disposal sites, and wind erosion at disposal sites.

GCA/Technology Division has estimated that air emissions resulting from dry ash handling and disposal are 0.5 kg/metric ton of ash landfill (1). This estimate was based on wind erosion data which showed that the erosion of soils having particle diameters less than 50 μm is minimal due to the attractive forces between particles and consideration of landfill erosion prevention practices. Using the GCA estimate, the hazard potential associated with air emissions from this point source was determined to be minor in comparison to stack fly-ash emissions. Based on the GCA estimates of fly ash and bottom ash collected for disposal and of stack emissions of noncollected fly ash, and assuming that 100% of the industrial ash is used as landfill in dry form, the emissions of ash from handling and disposal total less than 0.2% of the stack ash emissions. In addition, most fugitive ash emissions occur at landfills which are, in general, located more remotely than industrial sites and at ground level over a large land area; hence, the ash has a higher probability of redepositing on the landfill site.

Contamination of ground water and surface water by pond seepage or runoff containing landfill leachates presents a potential hazard. Leaching studies and ash pond liquor analysis (126, 127) indicate that coal ash and flue gas desulfurization sludges both contain sufficient quantities of soluble toxic materials to pose a threat to the quality of ground water and nearby surface waters. The results of an ash leachate measurement for a bottom ash and fly ash composite from the source sampled are presented in Table 46.

The magnitude of the environmental impact of ground and surface water pollution from leachates depends on a number of factors which include the chemical and physical nature of the ash and/or

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(127) Holland, W., K. Wilde, J. Parr, P. Lowell, and R. Pohler. Environmental Effects of Trace Elements from Ponded Ash and Scrubber Sludge. EPRI 202 (PB 252 090), Electric Power Research Institute, Palo Alto, California, September 1975. 403 pp.

TABLE 46. RESULTS OF THE ASH LEACHATE MEASUREMENT

Element[a]	Ash composition, g/kg of ash	Amount of element leached, mg/kg of ash	Percent leached
Aluminum	170	45	0.026
Barium	3.6	2.2	0.059
Boron	1.0	24	2.3
Calcium	49	800	1.8
Magnesium	13	27	0.22
Molybdenum	0.34	5.3	1.6
Sodium	11	210	1.8
Silicon	2.5[b]	9.5	0.38
Strontium	6.2	24	0.39
Vanadium	2.7	4.2	0.16

[a] Elements monitored but not found in leachate include antimony, cadmium, chromium, cobalt, copper, iron, lead, manganese, nickel, phosphorus, silver, tin, titanium and zinc.

[b] Value probably low due to an inability to completely digest silicon for analysis.

sludge, local weather conditions, distance from the disposal site to natural waters, design of the landfill or sludge pond, and the geology of the disposal site and surrounding areas. Most of these factors are site specific and probably unique for a given location. Therefore, no attempt will be made to quantify the potential effects for the average plant. A brief discussion of the findings of other researchers working in this area is presented below.

Leachate characteristics most likely to create a potential hazard are pH, oxygen demand (due to sulfite ion), total dissolved solids (TDS), and concentrations of toxic elements (123, 126-129). Besides directly affecting the receiving water, the pH value is a primary factor in determining the species and concentrations

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(128) Theis, T. L. The Potential Trace Metal Contamination of Water Resources Through the Disposal of Fly Ash. In: Proceedings of the Second National Conference on Complete Water Reuse; Waters Interface with Energy, Air and Solids; Chicago, Illinois, May 4-8, 1975. American Institute of Chemical Engineers, New York, New York, 1975. pp. 219-224.

(129) Rohrman, F. A. Analyzing the Effect of Fly Ash on Water Pollution. Power, August 1971. pp. 76-77.

of toxic elements in the leachate (130). Elements most likely to create a hazard because of their high toxicities and appreciable leaching rates are arsenic, barium, boron, chloride, chromium, lead, mercury, and selenium (124, 126, 127). On the whole, elemental concentrations actually observed in leachates are low, usually near the analytical detection limits, and the ion-exchange capacities of most soils are adequate for controlling most toxic elements for an extended period (>10 years for 10 m of soil) (127). In addition, these wastes tend to be self sealing due to the plugging of soil voids by the small particles which are characteristic of ash and sludge.

CONTROL OF EMISSIONS AND EFFLUENTS AT DISPOSAL SITES

As stated above, air and water pollution may result from the handling and disposal of waste solids. The optimum solution for controlling environmental contamination from solids disposal is to eliminate contaminants through recovery for reuse as previously discussed. Emission and effluent abatement methods for the handling and disposal of solids are briefly presented below.

Fugitive emissions from the loading of coal ash onto trucks can be minimized by wetting the coal ash and/or enclosing the transfer point to eliminate losses by wind entrainment and immediately cleaning up any spills that occur. Losses of waste materials during transport to a disposal site can be reduced by covering the ash or sludge after it is put on the truck, this practice is required in some areas. At disposal sites, emissions from wind erosion can be eliminated by adequately covering the disposed solids with earth as soon as possible.

Several methods exist for preventing pollution by leachates and runoff at pond and landfill sites. These methods include the use of liner materials, the construction of a perimeter ditch to collect leachate or runoff for treatment, and chemical fixation and stabilization of solid wastes prior to disposal.

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(130) Dreesen, D. R., E. S. Gladney, J. W. Owens, B. L. Perkins, C. L. Wienke, and L. E. Wangen. Comparison of Levels of Trace Elements Extracted from Fly Ash and Levels Found in Effluent Waters from a Coal-Fired Power Plant. Environmental Science and Technology, 11(10):1017-1019, 1977.

SECTION 7

FUTURE GROWTH AND TECHNOLOGY

Since the technological developments of the 1920's which made the use of pulverized coal practical, boilers firing pulverized coal have become the largest source of coal-derived, industrial energy. During this same period, the percentage of industrial energy supplied by coal has decreased dramatically because of the widespread availability of inexpensive gas and oil. However, a renewed interest in the use of coal has resulted from the oil producing and exporting countries' (OPEC's) oil embargo of late 1973 which sharply increased oil prices, the recent natural gas shortages, and the inception of government policies directed towards making the United States self-sufficient in energy. Known coal reserves in this country are capable of meeting our energy needs for the next 300 years at the current level of consumption, and coal prices are expected to remain relatively stable over the next several decades (131).

The extent of conversion to coal in the industrial sector during the 1980's can not be predicted. Major physical and economic constraints which limit rapid increases in coal usage include the following:

- A low equipment inventory of boilers capable of burning coal, coal and ash handling equipment, and pollution control equipment

- The time required to design and build a new boiler (∿5 years), although package boilers are available for smaller sizes

- The capital cost of converting units to burn coal

- The capital cost of installing pollution control equipment

- Fuel penalties for operating pollution control equipment

- The higher unit cost for handling coal in small quantities

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(131) Zweigle, M. L. Technological Feasibility of Alternative Energy Sources (AD A005 549). U.S. Army War College, Carlisle Barracks, Pennsylvania, October 1974. 31 pp.

- Potential irregularities in coal supply owing to strikes by coal miners

Even under the limitations listed above, industrial coal usage is expected to increase at a rate of 3% to 4% per year. These increases are not expected to change the relative mix of coal-fired units (e.g., the ratio of pulverizers to stokers, and other equipment combinations) (1). Total air emissions and wastewater effluents during this period are expected to remain constant or decrease slightly due to increased controls; the volume of solid wastes is expected to increase for the same reason.

The federal government could accelerate industry's conversion to coal by relaxing emission limitations and encouraging states to do the same. However, that approach is contrary to current long-range objectives. In addition, it is doubtful that the government could justify any increased rate of environmental degradation, especially considering that the preponderence of such boilers are located in or around urban areas which are already suffering from poor air quality. Other forms of government induced incentives, such as deregulation of natural gas and oil prices, reductions in rail freight rates for coal, and tax breaks for conversion to coal, may appreciably stimulate the growth rate of this source type should they be enacted.

It is not possible to predict the growth of this source type for the period beyond 1990 because of our rapidly changing energy situation and the current rate of energy research and development funding. If commercial size plants designed to convert coal into gaseous and liquid fuels are proven to be economical before 1985, the coal-fired boiler population could begin to decline; however, if coal cleaning plants are shown to be economically preferred, the population may continue to increase at least for a while. Sometime after 1990, the contribution from solar, geothermal and other alternative energy sources will begin to be felt, and it is predicted that these sources may supply a major share of the industrial energy consumed after 2050 (132).

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(132) Naill, R. F., J. S. Miller, and D. L. Meadows. The Transition to Coal. NSF-RA-N-74-289 (PB 256 445), National Science Foundation, Washington, D.C., November 1974. 51 pp.

SECTION 8

UNUSUAL RESULTS

The preparation of this report involved the evaluation of a considerable amount of literature and sampling data. During this process, several unusual or unexpected items were observed regarding the size range of the boilers studied and the field data obtained for sulfur oxides and elemental emissions.

BOILER SIZE DISTRIBUTION

A previous study defined the lower capacity limit for pulverized, coal-fired, dry bottom industrial boilers as 210 GJ/hr (1). This value is based on economic considerations (i.e., the cost of pulverizers versus the additional efficiency and throughput obtained by pulverizing). Values near or even substantially above this are frequently used in the literature for describing the capacities of pulverized coal-fired units in general (1, 29, 133). However, according to a NEDS listing of boilers specific to this source type (5), approximately 62% by number and 29% by total capacity of the boilers listed had capacities below this value. The capacities listed ranged downward to 1 GJ/hr. Figure 7 illustrates the distribution of boiler capacities found in NEDS.

POST-ESP SULFUR OXIDE EMISSIONS

Results of sulfur oxides measurements showed a reduction in the mass emission rate of SO_2 after passage through an electrostatic precipitator (see Table 14). Because of the limited amount of data, the reduction was not statistically significant, and further testing would be required to verify it. A review of the literature on SO_x emissions showed variations in SO_x values measured before and after precipitators but did not reveal any well-defined trends. However, a review of ESP operating characteristics provided several potential mechanisms for the conversion of SO_2 into SO_3 or SO_4, particularly when considering that the boiler was equipped with a "hot side" ESP; that is, the combustion gases flow directly from the furnace to the precipitator and then to

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(133) Exhaust Gases from Combustion and Industrial Processes. APTD-0805 (PB 204 861), Office of Air Programs Technical Center, Durham, North Carolina, October 2, 1971. 436 pp.

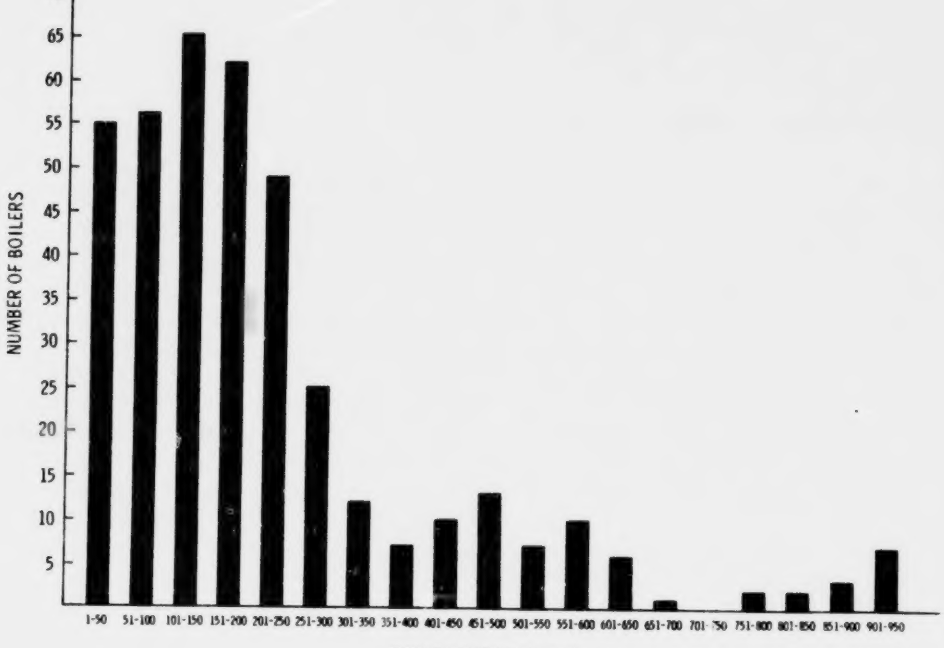

Figure 7. Distribution of boilers in this source type by design capacity (5).

heat recovery equipment. (Precipitators are used in this configuration for boilers firing low-sulfur coal as is the case for many western, coal-fired units.)

Two potential conversion mechanisms are postulated based on the input of energy from the ESP to the combustion gases via the corona discharges (electrical arcing across the electrodes). As one postulated conversion mechanism, consider that arcing in a precipitator may cause localized "hot spots" in which the conversion of SO_2 to SO_3 and/or SO_4 would occur quite rapidly because temperature is a dominant rate controlling factor. Because the gases are already hot in comparison to those encountered in an ESP in a conventional configuration, it is plausible that this additional heat input could cause the observed results. As a second postulated conversion mechanism, note that corona discharges have been also shown to produce ozone (O_3) which could readily react with SO_2 to yield SO_3 and O_2. This second mechanism was presented earlier to explain the apparent conversion of

N_2 to NO in an ESP (134). The variability of SO_2 emissions observed after the ESP can be explained by both of the above mechanisms because the degree of arcing is a function of the ash buildup on the electrodes.

SASS TRAIN TRACE METAL RESULTS

Analysis of the various SASS train components for elemental emissions showed that certain relatively nonvolatile elements were collecting beyond the particulate filter in the back half of the impinger series. Through a literature search, it was determined that some of these elements may partially exist in gaseous forms (32, 135); however, it was also determined that these elements were all components of the materials used in the construction of the train (i.e., iron, chromium, molybdenum and nickel from 316 stainless steel, and boron and silicon from the glass used for the impingers). From this information and the failure of a stainless steel tube leading to the first impinger during recent sampling of a gas stream containing chlorine (36), it was concluded that an unknown portion of the measured masses of these elements was due to contamination from corrosion of the train components.

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(134) Cuffe, S. T., R. W. Gerstle, A. A. Orning and C. H. Schwartz. Air Pollutant Emissions from Coal-Fired Power Plants; Report No. 1. Journal of Air Pollution Control Association, 14(9):353-362, 1964.

(135) Ulrich, G. D. An Investigation of the Mechanism of Fly-Ash Formation in Coal-Fired Utility Boilers--Interim Report for the Period February - May 1976. FE-2205-1, U.S. Energy Research and Development Administration, Washington, D.C., May 28, 1976. 9 pp.

(136) Personal communication with D. L. Harris, Monsanto Research Corporation, Dayton, Ohio, November 1977.

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APPENDIX A

SUMMARY OF NEDS DATA

Table A-1 presents selected data from the NEDS files for Standard Classification Codes SCC 1-02-002-02, SCC 1-02-002-08, and SCC 1-02-002-12 which correspond to external combustion of pulverized bituminous coal in dry bottom industrial boilers with design capacities ≥105 GJ/hr, 10.5 GJ/hr to 105 GJ/hr, and ≤10.5 GJ/hr, respectively. Obvious entries for utility and commercial/institutional units listed in these files have been omitted. The NEDS files do not list all boilers in this source category; many smaller boilers are not entered in the system. This point is discussed further in Section 3. Besides the NEDS data, county population densities calculated from population and land area information obtained from the 1970 census (137) are listed in the third column ofthe table.

Conversion factors used to provide metric values are shown at the end of this report. Abbreviations used in the eleventh column (Pollution Control Equipment) are as follows:

GC - gravity collector
CC - centrifugal collector
ESP - electrostatic precipitator
FF - fabric filter
WS - wet scrubber

The letter "C" is used to denote confidential information.

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TABLE A-1. SUMMARY OF NEDS DATA (5, 137)

State	County	County population density, persons/km²	Owner	Design capacity, GJ/hr	Annual operating rate, metric tons	Stack height, m	Gas flow rate, actual m³/s	Fuel sulfur content, %	Fuel ash content, %	Pollution control equipment type	Particulate control efficiency, %
Alabama	Morgan	51.8	Monsanto Textiles	C	C	58	5.7	0.64	7.0	ESP	99.0
Georgia	Chattooga	24.5	Riegel Textile Corp.	211	13,154	66	42.5	0.89	10.0	CC	40.0
				63	3,946	66	11.8	0.89	10.0	CC	40.0
				63	3,946	66	11.8	0.89	10.0	CC	40.0
				105	6,577	66	18.9	0.89	10.0	CC	40.0
	Floyd	54.7	Georgia Kraft Co.	1,194	26	55	169.7	1.00	10.0	ESP	99.5
			Celanese Fibers Co.	109	15,513	69	19.3	0.85	12.0	ESP-GC	95.0
Idaho	Bonneville	10.9	Utah Idaho Sugar Co.	C	C	15	-	0.72	4.5		
				C	C	49	0.7	0.80	7.5		
	Canyon	40.2	Amalgamated Sugar Co.	227	18,144	76	51.1	0.72	8.0	FF	99.0
				-	43,999	30	49.0	0.46	8.0	WS	99.0
	Minidoka	8.0		C	C	39	60.5	0.72	8.0	WS	76.0
				C	C	30	53.4	0.72	8.0	CC	79.0
	Twin Falls	8.1		C	C	69	68.5	0.75	8.0		
				C	C	46	46.3	0.53	5.0	FF	99.5
Illinois	Cook	2,196.5	Ford Motor Co.	53	10,900	24	14.7	0.80	8.5	FF	90.0
				53	10,900	24	14.7	0.80	8.5	FF	90.0
				32	10,900	24	14.7	0.80	8.5	FF	90.0
	Franklin	33.5	Inland Steel Co.	140	10,400	32	-	0.60	12.0	CC-WS	99.0
	Fulton	18.3	Ayreshire Coal Co.	162	700	24	-	2.70	5.2		
	Grundy	23.0	Morris Paper Mills	189	49,900	-	-	2.60	6.0		
	Knox	32.1	Galesburg Malleable	40	4,400	12	-	0.07	2.6		
	Lake	316.9	Abbott Laboratories	47	19,100	49	5.0	1.20	8.7	ESP	99.0
	Macon	83.1	Staley Mfg. Co.	186	41,700	102	-	2.80	8.7		
				103	29,800	102	-	2.80	8.7		
				191	43,000	76	-	2.80	8.7	GC	50.0
				191	44,900	76	-	2.70	8.7	GC	50.0
				190	50,700	102	-	2.80	8.7	GC	50.0
				195	50,300	102	-	2.80	8.7	GC	50.0
				195	47,000	102	-	2.80	8.7	GC	50.0
				223	58,600	102	-	2.80	8.7	GC	50.0
	Madison	130.0	Alton Box Board Co.	180	37,200	59	27.9	3.50	12.0	ESP	98.9
				469	113,400	59	169.8	3.50	12.0	ESP	98.7
	Peoria	120.0	Walker and Son	209	0	71	20.8	2.30	8.6	CC	86.3
				258	67,100	71	41.5	2.30	8.6	CC	90.8

(continued)

TABLE A-1 (continued)

State	County	County population density, persons/km²	Owner	Design capacity, GJ/hr	Annual operating rate, metric tons	Stack height, m	Gas flow rate, actual m³/s	Fuel sulfur content, %	Fuel ash content, %	Pollution control equipment type	Particulate control efficiency, %
Illinois (cont.)											
	St. Clair	159.4	Carling Brewing Co.	20	6,800	69	14.8	3.30	10.0	FF	46.5
				20	6,800	69	14.8	3.30	10.0	FF	46.5
			Charles Meyer Co.	4	500	21	1.0	4.00	9.8		
	Will	275.1	Statesville Pen	28	9,100	67	-	2.50	6.1		
			Uniroyal J-A-A-P	105	25,800	36	-	1.80	10.2		
				105	25,800	36	-	1.80	10.2		
				105	25,700	36	-	1.80	10.2		
	Williamson	43.0	21 Egler Coal Co.	13	2,100	-	-	3.00	9.5		
Indiana	Clark	75.8	U.S. Army Ammunition Plant	221	0	47	12.8	4.30	10.2		
				221	0	47	12.8	4.30	10.2		
				221	0	47	12.8	4.30	10.2		
				221	0	47	12.8	4.30	10.2		
				221	0	47	12.8	4.30	10.2		
			Colgate Palmolive	81	48	58	26.9	2.80	11.0		
	Lake	408.8	Inland Steel	480	98,000	69	91.1	2.53	10.9	CC	-
				480	98,000	69	91.1	2.53	10.9	CC	85.0
				480	98,000	69	91.1	2.53	10.9	CC	85.0
				480	98,000	69	91.1	2.53	10.9	CC	85.0
			Youngstown Sheet & Tube	980	71,500	52	459.6	0.73	9.0	CC-WS	85.0
	Marion	104.5	FMC Corp.	7	100	53	-	0.70	6.0		
				7	100	53	-	0.70	6.0		
				25	1,500	53	-	0.70	6.0		
				25	1,500	53	-	0.70	6.0		
				25	1,500	53	-	0.70	6.0		
			Stokely-Van Camp	74	6,500	61	24.5	0.97	15.0	GC	85.0
				74	6,500	61	20.2	0.97	5.0	GC	85.0
	St. Joseph	201.5	Uniroyal, Inc.	161	4,800	76	3.4	1.00	5.5	CC	85.5
				161	4,800	76	3.4	1.00	5.5	CC	85.5
				161	4,800	76	3.4	3.00	8.0	CC	85.5
	Tippecanoe	83.6	Alcoa-Lafayette	42	6,400	61	16.8	2.41	10.3	ESP	99.0
Iowa	Black Hawk	90.1	Rath Packing Co.	C	C	59	29.3	2.31	7.7	CC	80.0
			John Deere	-	250	9	2.7	1.40	9.4		
				74	440	50	2.2	1.40	9.4		
	Cerro Gordo	32.7	Lehigh Portland Cement	-	0	13	143.8	-	-	FF	99.5

(continued)

TABLE A-1 (continued)

State	County	County population density, persons/km²	Owner	Design capacity, GJ/hr	Annual operating rate, metric tons	Stack height, m	Gas flow rate, actual m³/s	Fuel sulfur content, %	Fuel ash content, %	Pollution control equipment type	Particulate control efficiency, %
Iowa (cont.)	Clinton	31.4	Clinton Corn	-	3,100	17	0.5	2.60	8.0	CC-FF	99.0
				-	11,300	17	0.2	2.60	8.0	CC-FF	99.0
				-	14,100	17	0.2	2.60	8.0	CC-FF	99.0
				-	83,700	17	1.1	2.60	8.0	CC-FF	99.0
				-	109,800	17	2.9	2.60	8.0	FF	99.0
	Des Moines	44.0	IA Army Ammunition Plant	47	23,400	21	0	3.30	9.2	CC	65.0
	Lee	30.7	Consolidated Packaging	38	1	69	0	4.00	10.4		
	Muscatine	32.0	Grain Processing	119	970	56	28.1	2.63	8.1		
				119	4,600	56	28.1	2.63	8.1		
				105	3,400	30	21.4	2.63	8.1		
				105	2,950	27	21.4	2.63	8.1		
	Scott	120.0	Linwood Stone Prod.	-	9,100	0	22.7	2.70	5.4	CC-GC	95.0
				-	9,100	0	22.7	2.70	5.4	CC-GC	95.0
				-	9,100	0	22.7	2.70	5.4	CC-GC	95.0
			Oscar Mayer & Co.	95	14,200	43	23.6	2.70	7.6	CC	90.0
				104	14,200	43	23.6	2.70	7.6	CC	90.0
				35	3,500	27	6.6	2.70	7.6		
				95	14,500	43	23.6	0.70	7.9	CC	90.0
Kansas	Cherokee	14.0	Gulf Oil Chemicals	C	C	34	-	3.50	12.0	ESP	97.0
Kentucky	Boyd	122.7	Ashland Oil, Inc.	218	25,700	46	10.1	0.90	8.0		
			Pittsburgh Act. Carbon	82	0	37	7.1	0.50	2.2	CC	52.0
	Meade	22.7	Olin Corp.	229	57,700	38	34.5	2.02	14.3	CC-ESP	97.0
				229	57,700	38	33.0	2.02	14.4	CC-ESP	99.2
				229	57,700	30	34.9	2.02	14.4	CC-ESP	99.2
	Muhlenburg	21.7	Island Creek Coal Co.	3	180	21	6.0	3.20	6.4		
				1	90	9	1.5	3.20	6.4		
Maryland	Allegany	74.1	West Virginia Pulp & Paper	622	152,400	53	-	2.70	15.0	ESP	99.0
				827	196,000	69	-	2.40	15.0	CC-ESP	96.0
	Washington	85.2	Western Md. RR	42	4,870	34	7.8	2.60	6.8	CC	92.0
				42	4,870	34	7.8	2.60	6.8	CC	92.0
Massachusetts	Merrimack Valley APCO	277.5	Boston & Maine	87	12,400	53	8.3	1.56	8.0		
Michigan	Calhoun	76.3	General Foods Corp.	182	18,100	60	-	1.00	5.8	CC	93.5
				145	2,300	60	-	1.00	5.8	CC	93.3
			General Service Admin.	22	5,000	69	84.9	2.30	5.5	CC	85.0
	Genesee	265.6	Chevrolet Division, GMC	153	17,100	46	14.9	1.00	6.0	CC	94.0
			Buick Motor Division, GMC	506	50,000	76	98.6	1.08	8.7	ESP	98.8
				506	48,000	76	98.6	1.08	8.7	ESP	98.7
	Macomb	499.1	Michigan Army Missile Plant	105	19,100	-	-	1.10	6.0	CC	90.0

(continued)

TABLE A-1 (continued)

State	County	County population density, persons/km²	Owner	Design capacity, GJ/hr	Annual operating rate, metric tons	Stack height, m	Gas flow rate, actual m³/s	Fuel sulfur content, %	Fuel ash content, %	Pollution control equipment type	Particulate control efficiency, %
Michigan (cont.)											
	Midland	46.8	Dow Chemical Co.	822	84,400	55	-	3.80	11.8	CC	85.6
	Muskegon	120.3	S.O. Warren Paper Co.	126	19,200	-	-	1.70	7.0		
				126	17,900	-	-	1.70	7.0		
				348	75,800	-	-	1.70	7.0	CC-ESP	98.1
	Ontonagon	3.0	Hoerner Waldorf	282	54,400	46	40.7	2.71	7.9	CC	85.0
			White Pine Copper Co.	215	16,800	46	-	1.32	8.9	CC	89.6
				234	6,960	46	-	1.32	8.9	CC	90.8
			Mill Division - Paper Mill	395	28,700	46	94.4	3.50	9.2	CC	75.5
	Wayne	1,686.3	Allied Chemical	1,887	497,000	67	35.3	0.62	6.5		
			American Motors Corp.	22	1,810	46	6.5	0.70	7.5		
			Dearborn Glass Plant	885	71,600	95	-	0.78	11.4		
				885	71,600	95	-	0.78	11.4		
				1,012	71,600	95	-	0.78	11.4		
				632	89,400	95	-	0.78	11.4		
				1012	71,600	95	-	0.78	11.4		
				632	89,400	95	-	0.78	11.4		
				632	89,400	95	-	0.78	11.4		
			Cadillac Motor Car Division	126	6,050	38	39.6	0.64	14.1	ESP-CC	93.7
				126	6,320	38	39.6	0.64	14.1	ESP-CC	94.1
				126	8,920	38	39.6	0.64	14.1	ESP-CC	95.8
				126	6,680	38	39.6	0.64	14.1	ESP-CC	94.4
				126	7,310	38	19.8	0.64	14.1		
Minnesota	Anoka	139.8	Honeymead Products Co.	82	3,600	46	15.6	0.90	6.0		
	Freeborn	20.7	Wilson Sinclair	126	14,700	34	12.8	2.10	8.5	CC	65.0
Missouri	Pike	9.4	Hercules, Inc.	194	52,900	36	15.6	1.70	7.1	CC	25.0
				194	52,900	36	15.6	1.70	7.1	CC	25.0
				194	52,900	36	15.6	1.70	7.1	CC	25.0
	St. Louis	742.8	Anheuser Busch	c	c	69	20.4	3.65	10.6	ESP	90.0
				c	c	69	30.5	3.65	10.6	ESP	90.0
				c	c	69	17.6	3.60	10.6	ESP	91.7
			GMAD Chassis Side	c	c	69	28.5	2.92	10.2	ESP-WS	99.4 90.0[a]
				c	c	69	28.5	2.92	10.2	ESP-WS	99.4 90.0[a]

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[a] Percent SO_x control efficiency.

TABLE A-1 (continued)

State	County	County population density, persons/km²	Owner	Design capacity, GJ/hr	Annual operating rate, metric tons	Stack height, m	Gas flow rate, actual m³/s	Fuel sulfur content, %	Fuel ash content, %	Pollution control equipment type	Particulate control efficiency, %
New York	Cattaraugus	23.4	Moench Tanning	19	3,400	17	3.6	2.00	9.4	CC	67.0
				19	3,400	17	3.3	2.00	9.4	CC	67.0
	Erie	402.7	Anaconda America	74	12,500	38	12.1	1.60	12.1	CC-CC	92.8
	Essex	7.2	MacIntyre Development	35	4,700	41	13.8	2.30	8.0	CC-CC	90.0
	Genesee	44.9	U.S. Gypsum Co.	83	19,900	41	30.8	2.80	7.5	CC	88.0
	Jefferson	26.0	Crown Zellerbach	189	5	15	19.2	2.10	7.1	CC-CC	91.0
	Kings	14,132.7	Brooklyn Naval Shipyard	158	7,560	-	-	2.50	10.0		
				158	7,560	-	-	2.50	10.0		
				158	7,560	-	-	2.50	10.0		
				158	7,560	-	-	2.50	10.0		
				158	7,560	-	-	2.50	10.0		
				158	7,560	-	-	2.50	10.0		
	Monroe	404.2	Clark Stek-O Co.	22	-	40	-	1.90	7.2		
			Flower City Tissue	27	2,900	24	1.8	2.60	7.0	CC-CC	85.0
			Gleason Works	90	6,350	53	9.1	1.30	6.9		
			GMC Rochester Plant	153	10,900	53	5.1	1.00	9.8	CC-CC	90.0
				78	7,260	15	4.4	1.00	9.8	CC	92.0
	Niagara	169.2	Prestolite Division.	28	-	18	6.6	2.80	7.5		
				28	1	21	<0.1	2.80	7.5	CC	97.0
	Onondaga	226.8	Allied Chemical	295	83,500	46	51.9	3.00	13.0	ESP	99.0
				262	74,800	46	51.9	3.00	13.0	ESP	96.5
				262	74,800	46	51.9	3.00	13.0	ESP	96.5
				262	74,800	46	51.9	3.00	13.0	ESP	96.5
				262	74,800	46	51.9	3.00	13.0	ESP	96.5
				262	74,800	46	51.9	3.00	13.0	ESP	96.5
				401	113,000	64	-	3.00	13.0	ESP-ESP	96.9
	St. Lawrence	15.4	Norwhey Division	19	0	26	4.2	2.30	9.0		
	Schuyler	19.3	International Salt	110	12,000	69	26.5	2.40	7.0	CC-CC	96.0
	Wayne	50.2	Garlock, Inc.	94	1,800	30	8.5	1.50	10.0	CC	94.5
North Carolina	Avery	19.0	Harris Mining Co.	16	3,200	40	1.7	0.80	5.0		
	Buncombe	81.1	American Enka Co.	143	36,500	69	34.8	1.04	7.5	CC-CC	99.9
				143	36,500	69	32.9	1.04	7.5	CC	99.0
				215	54,700	53	40.0	1.04	7.5	CC-CC	83.5
				258	54,400	53	17.7	1.04	7.5	CC-CC	91.0
	Cabarrus	79.1	Kerr Bleach & Finishing	C	C	23	21.2	0.80	5.3		
			Cannon Mills Co.	C	C	53	1.4	0.84	5.5	CC	89.0
				C	C	53	2.0	0.84	5.5	CC	89.0

(continued)

TABLE A-1 (continued)

State	County	County population density, persons/km²	Owner	Design capacity, GJ/hr	Annual operating rate, metric tons	Stack height, m	Gas flow rate, actual m³/s	Fuel sulfur content, %	Fuel ash content, %	Pollution control equipment type	Particulate control efficiency, %
North Carolina (cont.)											
	Davidson	66.7	Thomasville Furn. Ind.	18	1,130	23	2.1	1.00	6.0	CC	99.3
				28	930	23	3.4	1.00	6.0	CC	93.9
	Forsyth	189.3	R. J. Reynolds Tobacco Co.	C	C	70	48.6	0.70	9.0	CC-ESP	97.7
				C	C	70	48.6	0.70	9.0	CC-ESP	97.7
				C	C	70	46.8	0.70	9.0	ESP	97.7
				C	C	70	46.8	0.70	9.0	ESP	97.7
	Guilford	168.0	Cone Mills	131	0	53	14.8	1.00	6.0	CC	80.0
				131	0	53	14.8	1.00	6.0	CC	80.0
				123	0	53	14.0	1.00	6.0	CC	80.0
				218	0	53	24.6	1.00	6.0	CC	80.0
	Halifax	27.7	Albemarle Paper Co.	C	C	64	102	1.25	10.0	WS	98.0
			J. P. Stevens	C	C	30	11.8	1.10	6.9	GC	25.0
				C	C	27	10.9	1.40	5.5		
	Haywood	28.2	U.S. Plywood	316	90,700	76	288	1.30	18.0	ESP	99.0
				316	90,700	76	288	1.30	18.0	ESP	99.0
				337	99,800	46	38.3	1.30	18.0	ESP	71.9
				360	19,600	46	54.6	1.30	18.0		
	Iredell	46.8	Mooresville Mill	95	120	15	38.2	0.97	4.0		
				95	120	15	38.2	0.87	4.0		
	McDowell	24.3	Broyhill	40	330	38	61.4	0.88	6.6		
			Old Fort Finishing	39	8,500	24	10.8	1.60	8.6		
				39	8,500	24	10.8	1.60	8.6		
				48	10,300	27	13.1	1.60	8.6		
			Drexel	19	860	15	7.6	1.00	6.0		
			Burlington Industries	22	24	23	2.1	0.70	6.0		
	Polk	18.6	Southern Mercerizing	18	1,050	41	-	0.76	4.8		
	Rockingham	48.1	American Tobacco Co.	93	0	67	18.8	1.20	11.0		
				39	0	67	7.9	1.20	11.0		
				156	25	67	30.6	1.20	11.0	CC	90.0
				156	24	67	30.6	1.20	11.0	CC	90.0
	Rowan	67.0	Fieldcrest Mills	95	11,300	24	30.7	0.90	9.0		
	Transylvania	18.9	Olin Corp.	C	C	36	41.3	1.60	10.0	ESP	99.0
				C	C	37	26.4	1.60	10.0	ESP	99.0
				C	C	37	54.6	1.60	10.0	ESP	99.0

(continued)

TABLE A-1 (continued)

State	County	County population density, persons/km²	Owner	Design capacity, GJ/hr	Annual operating rate, metric tons	Stack height, m	Gas flow rate, actual m³/s	Fuel sulfur content, %	Fuel ash content, %	Pollution control equipment type	Particulate control efficiency, %
Ohio	Butler	178.9	Crystal Tissue Co.	148	20,900	20	18.9	0.70	7.5	ESP	98.0
			Diamond International Corp.	139	27,600	21	25.0	0.70	6.0	ESP	92.5
			Sorg Paper Co.	203	39,100	61	42.6	0.90	8.7	WS	99.0
				105	10,900	61	19.1	0.90	8.7	FF	99.0
				105	16,200	61	19.1	0.90	8.7		
				105	13,400	61	19.1	0.90	8.7	WS	99.0
			Hamilton Mil-Champ Papers	442	114,000	67	118	0.87	11.0	CC	75.0
	Cuyahoga	1,440.8	Aluminum Co. of America	79	7,300	61	11.5	2.50	7.0		
				79	7,300	61	11.5	2.50	7.0		
				79	7,300	61	11.5	2.50	7.0		
				79	7,300	46	11.5	2.50	7.0		
				79	7,300	46	11.5	2.50	7.0		
			Republic Steel Corp.	354	43,100	51	86.8	2.00	15.0	CC	85.0
				354	43,100	44	86.8	2.00	15.0	CC	85.0
				354	43,100	44	86.8	2.00	15.0	CC	85.0
				486	119,000	69	81.2	2.00	15.0	CC	91.4
				242	16,300	46	170	2.00	15.0		
				242	16,300	46	170	2.00	15.0		
				353	85,000	37	82.4	1.00	10.0		
	Franklin	591.3	Naval Weapons Ind. Res. Plant	83	2,470	23	17.5	3.50	6.7	ESP-CC	96.8
				83	2,100	23	17.5	3.50	6.7	ESP-CC	96.8
				83	3,760	23	17.5	3.50	6.7	ESP-CC	96.8
				187	5,250	23	35.4	3.50	6.7	ESP-CC	96.8
	Hamilton	853.7	Emery Industries, Inc.	162	40,800	24	14.5	0.89	7.3		
				263	14,100	24	32.1	0.89	7.3		
				162	45,100	24	14.5	0.70	6.6		
				263	69,600	24	32.1	0.70	6.6		
			Fox Paper, Inc.	102	18,100	53	35.4	0.75	6.5	CC	85.0
			General Electric	116	246	18	17.9	1.25	10.0	CC	88.0
				156	26,400	23	17.8	1.25	10.0	CC	82.0
			Diamond International Corp.	160	36,000	18	23.6	0.70	11.0	CC-ESP	90.0
			Procter & Gamble Co.	292	34,000	53	51.9	0.70	13.0	ESP	90.0
			Sherwin Williams Chemicals	70	3,970	55	6.5	0.78	5.9	CC	85.0
	Jefferson	89.4	Wheeling Pittsburg Steel	84	12,700	84	44.6	3.00	8.5		
				84	12,700	84	44.6	3.00	8.5		
				84	1,520	77	44.8	3.00	8.5		

(continued)

TABLE A-1 (continued)

State	County	County population density, persons/km²	Owner	Design capacity, GJ/hr	Annual operating rate, metric tons	Stack height, m	Gas flow rate, actual m³/s	Fuel sulfur content, %	Fuel ash content, %	Pollution control equipment type	Particulate control efficiency, %
Ohio (cont.)	Jefferson	89.4	Wheeling Pittsburg Steel	84	1,520	77	44.8	3.00	8.5		
				84	1,520	77	44.8	3.00	8.5		
				84	1,520	77	44.8	3.00	8.5		
				84	1,520	77	44.8	3.00	8.5		
				222	5,900	36	26.9	3.00	8.5		
				222	5,480	36	26.9	3.00	8.5		
				222	6,070	36	26.9	3.00	8.5		
	Lake	326.4	Diamond Shamrock Chemicals	447	112,500	49	77.9	3.44	12.8	ESP	95.0
				491	117,000	54	97.2	3.44	12.8	ESP	95.0
			Uniroyal Chemicals Division	135	12,300	53	59.0	4.00	11.0		
				135	12,300	53	59.0	4.00	11.0		
	Lawrence	46.9	Allied Chemical Corp.	184	27,900	38	34.4	3.30	14.0		
				184	27,900	38	34.4	3.30	14.0		
	Mahoning	277.8	Youngstown Sheet & Tube	497	18,500	41	118	2.79	11.9		
				497	18,500	41	118	2.79	11.9		
				297	11,100	41	73.8	2.79	11.9		
				297	11,100	41	77.8	2.79	11.9		
				297	11,100	41	77.8	2.79	11.9		
				297	11,100	41	73.8	2.79	11.9		
			Republic Steel Corp.	430	9,890	48	89.7	3.50	13.8	CC	90.0
				430	9,890	48	89.7	3.50	13.8	CC	90.0
			U.S. Steel Corp.	327	4,130	43	21.8	1.00	13.3		
				327	4,130	43	21.8	1.00	13.3		
				327	4,130	43	21.8	1.00	13.3		
				327	4,130	43	21.8	1.00	13.3		
	Montgomery	498.2	Inland Division	99	10,100	53	35.9	0.76	12.3	CC-ESP	99.0
				103	10,400	53	35.9	0.76	12.3	CC-ESP	99.0
				139	14,200	53	27.4	0.76	12.3	ESP	99.0
			Frigidaire	103	12,400	61	27.2	0.60	13.7	CC-ESP	98.4
				103	12,400	61	20.9	0.60	13.7	CC-ESP	98.7
				103	12,400	61	23.1	0.60	13.7	CC-ESP	99.5
				103	12,400	61	22.5	0.60	13.7	CC-ESP	99.5
			Miami Paper Corp.	137	32,700	67	26.0	0.80	8.6	CC-WS	95.7
	Stark	248.5	Wean United, Inc.	3	950	24	13.2	0.71	8.6		
				3	0	24	13.2	0.71	8.6		
			Republic Steel Corp	59	5,600	90	15.2	3.00	4.8		

(continued)

TABLE A-1 (continued)

State	County	County population density, persons/km²	Owner	Design capacity, GJ/hr	Annual operating rate, metric tons	Stack height, m	Gas flow rate, actual m³/s	Fuel sulfur content, %	Fuel ash content, %	Pollution control equipment type	Particulate control efficiency, %
Ohio (cont.)	Stark	248.5	Republic Steel Corp.	59	5,600	90	15.2	3.00	4.8		
				59	5,600	90	15.2	3.00	4.8		
				59	5,600	90	15.2	3.00	4.8		
				59	5,600	90	15.2	3.00	4.8		
	Summit	514.4	Firestone Tire & Rubber Co.	577	88,100	69	88.8	3.10	9.9	CC	91.0
				577	102,000	69	88.8	3.10	9.9	CC	91.0
			Goodyear Tire & Rubber Co.	201	47,400	76	16.7	3.70	12.9	ESP	99.0
				173	40,600	72	23.2	3.70	12.9	CC	85.0
				347	81,600	76	46.0	3.70	12.9	CC	85.0
				347	81,600	76	46.0	3.70	12.9	CC	85.0
	Trumbull	144.2	Republic Steel Corp.	587	25,500	46	89.7	2.80	13.0	CC	65.0
	Tuscarawas	53.7	U.S. Concrete Pipe Co.	28	4,200	53	-	3.01	5.6		
				-	2,200	53	-	3.01	5.6		
Oregon	Malheur	0.9	Amalgamated Sugar Co.	-	37,000	46	-	-	-	CC-FF	94.0 99.7[a]
				-	36,300	-	-	-	-	CC	94.0
				-	22,300	46	-	-	-	CC-FF	94.0 99.7[a]
Pennsylvania	Adams	41.1	P. H. Glatfelter	148	34,700	61	32.4	3.50	8.0	CC	90.7
				376	58,700	61	67.7	3.50	8.0	CC	88.0
				271	66,000	61	49.7	3.50	8.0	WS	92.7
	Allegheny	841.6	U.S. Steel	223	7,950	46	38.5	2.00	9.0	CC	92.0
				223	7,950	46	38.5	2.00	9.0	CC	92.0
				223	7,950	46	38.5	2.00	9.0	CC	92.0
				223	7,950	46	38.5	2.00	9.0	CC	92.0
			Westinghouse Electric	196	16,500	-	-	1.75	13.1		
			Koppers Pittsburg Co.	113	17,300	32	35.0	2.20	9.0	CC	85.0
			U.S. Steel	151	2,860	50	36.0	1.48	5.9		
				151	2,860	50	36.0	1.48	5.9		
				151	2,860	50	36.0	1.48	5.9		
				676	7,950	43	202	1.97	8.3		
				530	7,960	43	155	1.97	8.3	CC	85.0
				507	135,000	50	73.1	1.62	6.7	CC-ESP	96.0

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[a] Percent SO_x control efficiency.

(continued)

TABLE A-1 (continued)

State	County	County population density, persons/km²	Owner	Design capacity, GJ/hr	Annual operating rate, metric tons	Stack height, m	Gas flow rate, actual m³/s	Fuel sulfur content, %	Fuel ash content, %	Pollution control equipment type	Particulate control efficiency, %
Pennsylvania (cont.)	Allegheny	841.6	Pittsburg Brewing Co.	23	4,350	63	17.0	2.80	7.5		
				23	4,350	63	17.0	2.80	7.5		
			Union Carbide Corp.	177	55,600	48	174	2.75	14.0	CC	81.5
				177	55,600	48	174	2.75	14.0	CC	81.5
				177	55,600	48	174	2.75	14.0	CC	81.5
	Beaver	180.4	Sinclair-Koppers Co.	495	95,300	61	134	3.12	16.9	ESP	98.6
				495	95,300	61	134	3.12	16.9	ESP	98.6
				495	95,300	61	134	3.12	16.9	ESP	98.6
				495	43,700	61	134	3.12	16.9	ESP	98.6
			Crucible, Inc.	105	31,800	44	47.7	2.20	15.0	ESP	98.0
	Blair	97.5	Westvaco Corp.	116	23,900	72	24.0	2.00	10.0		
				116	23,900	72	24.0	2.00	10.0		
	Buttler	60.6	Sonneborn Division-Witco Chem.	50	15,900	61	20.3	2.50	9.0	CC	86.0
				85	23,900	61	33.3	2.50	9.0	CC	86.0
				85	23,900	61	33.3	2.50	9.0	CC	88.0
				131	31,800	61	45.4	2.50	9.0		
	Crawford	29.8	FMC Corp.	181	45,700	62	104	2.00	13.0	CC	85.0
				181	45,700	62	104	2.00	13.0	CC	85.0
				181	45,700	62	104	2.00	13.0	CC	85.0
				181	45,700	62	104	2.00	13.0	CC	85.0
	Cumberland	109.3	C. H. Masland & Sons	101	6,390	46	28.2	3.30	7.7	CC	83.5
	Dauphin	163.4	Hershey Foods Corp.	163	11,100	76	64.1	2.25	11.8		
				163	11,100	76	64.1	2.25	11.8		
				163	6,060	76	34.8	2.25	11.8		
				163	15,200	76	42.4	2.25	11.8		
				190	24,200	76	84.8	2.25	11.8		
	Elk	17.7	Penntech Papers, Inc.	74	19,400	37	61.6	2.25	10.5	CC	87.2
	Erie	122.6	Hammermill Paper Co.	130	5,150	67	20.2	2.70	12.0		
				130	5,150	67	20.2	2.70	12.0		
				217	46,500	67	33.9	2.70	12.0	CC	93.0
				217	46,500	67	37.2	2.70	12.0	CC	93.0

(continued)

TABLE A-1 (continued)

State	County	County population density, persons/km²	Owner	Design capacity, GJ/hr	Annual operating rate, metric tons	Stack height, m	Gas flow rate, actual m³/s	Fuel sulfur content, %	Fuel ash content, %	Pollution control equipment type	Particulate control efficiency, %
Pennsylvania (cont.)											
	McKean	19.7	Quaker State Oil	106	25,900	46	27.1	1.16	11.2	CC	88.0
				96	24,000	61	33.0	1.16	11.2	CC	90.0
				96	24,000	61	33.0	1.16	11.2	CC	90.0
	Washington	94.3	Wheeling Pittsburg Steel Corp.	53	900	34	6.1	2.01	7.9		
				53	900	34	6.1	2.01	7.9		
				53	900	34	6.1	2.01	7.9		
				53	900	34	6.1	2.01	7.9		
				154	2,850	34	10.3	2.01	7.9		
				154	2,850	34	10.3	2.01	7.9		
Tennessee	Davidson	401.9	DuPont	586	7,330	61	103	2.50	8.0		
				269	2,140	61	152	3.00	8.0		
				269	2,140	61	-	3.00	8.0		
				286	2,280	61	-	3.00	8.0		
				415	3,310	61	78.8	3.00	8.0		
			Neuhoff Packing	15	0	63	-	-	-		
	Hamblen	92.4	American Enka	190	31,900	76	168	0.90	15.0	CC	62.5
				190	31,900	76	168	0.90	15.0	CC	62.5
				190	31,900	76	168	0.90	15.0	CC	62.5
				190	31,900	76	168	0.90	15.0	CC	62.5
				190	31,900	76	168	0.90	15.0	CC	62.5
				190	31,900	76	168	0.90	15.0	CC	62.5
				290	51,300	76	95.5	0.90	15.0	CC	62.5
	Hamilton	170.4	DuPont	69	12,500	30	11.2	2.40	14.0	CC	97.0
	Hawkins	26.8	Holsten Army Ammo. Plant	250	0	35	21.1	0.62	8.0		
				270	0	35	26.4	0.60	10.0		
	Sullivan	116.4	Tennessee Easman Co.	584	186,000	76	56.6	0.75	18.5	CC-ESP	99.2
				584	186,000	76	56.6	0.75	18.5	CC-ESP	99.1
				584	186,000	76	56.6	0.75	18.5	CC-ESP	99.0
				584	186,000	76	56.6	0.75	18.5	CC-ESP	28.4
				584	158,000	76	56.6	0.89	14.7	CC-ESP	99.0
			Holsten Army Ammo. Plant	271	20,600	35	28.7	0.60	6.5	CC	85.0
			Mead Corp.	105	0	54	47.0	0.94	13.0	GC	85.0
				105	0	54	47.0	0.94	13.0	GC	85. 0
				105	21,000	54	47.0	0.94	13.0	CC	85.0

(continued)

TABLE A-1 (continued)

State	County	County population density, persons/km²	Owner	Design capacity, GJ/hr	Annual operating rate, metric tons	Stack height, m	Gas flow rate, actual m³/s	Fuel sulfur content, %	Fuel ash content, %	Pollution control equipment type	Particulate control efficiency, %
Tennessee (cont.)											
	Washington	86.0	Varsity Cleaners	1	43	7	0.3	0.88	3.7		
Utah	Salt Lake	235.8	Kennecott Copper	C	C	44	14.2	0.86	8.0	CC	25.0
				C	C	44	14.2	0.86	8.0	CC	25.0
				C	C	44	14.2	0.86	8.0	CC	25.0
	Utah	26.4	U.S. Steel Corp.	434	11,600	61	87.3	0.60	6.7		
				434	11,600	61	87.3	0.60	6.7		
				434	11,600	61	87.3	0.60	6.7		
Virginia	Alleghany	10.7	Westvaco Corp.	544	46,300	98	17.1	1.30	10.0	CC-WS	88.0
				764	198,000	56	44.2	1.30	10.0	ESP	95.0
	Augusta	17.0	DuPont	207	46,400	76	89.2	1.22	12.2	CC	83.7
				220	23,000	76	89.2	1.22	12.2	CC	88.8
				220	26,900	76	89.2	1.22	12.2	CC	88.0
				186	36,100	76	89.2	1.22	12.2	CC	83.4
				193	15,800	46	44.2	1.22	12.2	CC	74.1
	Bedford	13.2	Owens-Illinois	295	112,500	61	198	1.00	8.5	CC	87.0
	Buckingham	6.7	Stolite Corp.	C	C	-	84.3	2.85	12.0	WS	60.0
	Campbell	31.1	Mead Corp.	276	85	42	16.3	1.56	9.9	CC	65.3
	Chesterfield	63.7	DuPont	752	32,700	76	78.9	1.14	9.9	CC	84.0
	Giles	17.6	Celanese Fibers Co.	207	45,400	43	21.6	1.15	11.0	ESP	90.0
				417	98,000	43	25.5	1.15	11.0	ESP	90.0
				548	472	43	59.0	1.15	11.0	ESP	90.0
				333	287	46	38.0	1.15	11.0	CC	99.0
	Henry	50.1	DuPont	527	63,500	47	64.8	1.40	9.6	CC	90.0
			Hooker Furniture Corp.	19	230	30	-	-	-		
	Montgomery	45.2	Hercules (Radford Army Arsenal)	1,054	195,000	15	52.6	1.20	12.0	CC	75.0
				158	20,200	49	12.1	0.70	12.0		
	Pittsylvania	22.0	Dan River, Inc.	612	44,000	76	122.0	1.20	7.1	CC	85.6
	Pulaski	34.1	Pulaski Furniture Co.	21	726	27	-	0.60	4.1	CC	50.0
	Warren	26.5	FMC Corp.	892	176,000	58	57.0	1.20	11.0	CC	34.0
				631	117,000	58	57.0	1.20	11.0	CC	70.0
	Wise	33.6	Coal Processing Corp.	1	154	13	-	0.67	2.1		
Washington	Yakima	12.9	U & I Sugar	211	34,500	61	27.3	1.00	6.0		

(continued)

TABLE A-1 (continued)

State	County	County population density, persons/km²	Owner	Design capacity, GJ/hr	Annual operating rate, metric tons	Stack height, m	Gas flow rate, actual m³/s	Fuel sulfur content, %	Fuel ash content, %	Pollution control equipment type	Particulate control efficiency, %
West Virginia	Brooke	129.0	Koppers, Co.	47	4,230	61	18.1	1.97	9.2	GC	40.0
				74	11,700	61	18.1	1.97	9.2	GC	40.0
				74	8,490	44	7.3	1.97	9.2	GC	40.0
	Kanawha	95.4	Union Carbide Corp.	137	9,800	46	35.4	1.05	12.2	ESP	99.0
				137	9,800	46	35.4	1.05	12.2	FF	99.0
				211	15,100	46	54.3	1.05	12.2	FF	99.0
				211	15,100	46	54.3	1.05	12.2	FF	99.0
				211	15,100	46	54.3	1.05	12.2	FF	99.0
				211	15,100	47	51.9	1.05	12.2	FF	99.0
				211	15,100	47	51.9	1.05	12.2	FF	99.0
				348	21,500	46	89.7	1.05	12.2	FF	99.0
				227	15,900	38	47.2	1.00	13.0	CC-ESP	99.7
				227	15,900	38	47.2	1.00	13.0	CC-ESP	99.7
				227	15,900	38	47.2	1.00	13.0	CC-RSP	99.7
				227	15,900	38	47.2	1.00	13.0	CC-ESP	99.7
				227	15,900	38	47.2	1.00	13.0	CC-ESP	99.7
				227	15,900	38	47.2	1.00	13.0	CC-ESP	99.7
				227	15,900	38	47.2	1.00	13.0	CC-ESP	99.7
				227	15,900	38	47.2	1.00	13.0	CC-ESP	99.7
Wisconsin	Chippewa	17.9	St. Regis Paper Co.	110	8,290	46	20.8	2.10	9.9		
	Eau Claire	38.8	Uniroyal, Inc.	149	20,200	55	10.8	2.50	11.0	CC	-
				149	17,600	55	10.8	2.50	11.0		
	Marinette	9.8	Niagra-Wisc. Paper Co.	106	21,600	47	80.2	2.60	9.8		
				106	19,300	47	8.0	2.60	9.8		
				106	21,600	47	8.0	2.60	9.8		
	Racine	196.2	Young Radiator	2	380	24	-	0.70	8.2		
	Wood	31.3	Nekoosa Edwards Paper	C	C	65	99.1	2.10	9.1	ESP	98.5
				C	C	65	99.1	2.10	9.1	ESP	98.5
Wyoming	Sweetwater	0.7	Allied Chemical	563	116,000	48	118	0.64	2.9	ESP	98.1
				928	122,000	48	191	0.55	3.0	ESP	98.0

Note.—Blanks indicate no control device listed, dashes (-) indicate that the information is not available.

APPENDIX B

RIVER FLOW RATE DATA

Because information on wastewater treatment practices is unavailable, it is assumed that effluents generated by boilers in the source type studied are discharged directly to a river. The receiving river for discharges from the average plant (see Sections 4 and 6) was characterized by averaging the flow rates of rivers located near the boilers in the NEDS listing (7). Boiler locations were identified by city, and nearby rivers were located using area road maps and U.S. Geological Survey (USGS) data (88-115). Average and minimum flow rates were also obtained from the USGS reports using data from gaging stations located in or near the cities of interest, or by averaging data from gaging stations located above and below these cities. When two or more rivers were found in the same city, the river with the largest average flow rate was selected as the most likely receiving body.

Table B-1 summarizes the river flow rate data on a state-by-state basis. Table B-2 lists the cities, rivers, and flow rates used in calculating the average river characteristics. Values presented for average flow and minimum flow are averages of data for two years (1974 and 1975). Blanks in Table B-1 and B-2 indicate that no data were found.

The average of the minimum river flow rates was used in the source severity calculations. Average river flow rates are presented for comparison.

TABLE B-1. SUMMARY OF RIVER FLOW RATE DATA (88-115)

State	Number of rivers averaged	Average river flow rate, m^3/s	Average minimum river flow rate, m^3/s
Alabama	0		
Georgia	1	94.9	19.6
Idaho	4	182.5	40.0
Illinois	8	1,360	407.7
Indiana	2	139.3	20.9
Iowa	7	1,135	389.4
Kansas	0		
Kentucky	2	4,904	1,756
Maryland	0		
Massachusetts	1	248.6	41.1
Michigan	7	32.7	8.31
Minnesota	1	373.8	51.4
Missouri	1	5,012	2,299
New York	4	1,736	1,266
North Carolina	5	85.6	16.6
Ohio	9	718.6	374.6
Oregon	1	538.3	442.2
Pennsylvania	13	440.7	55.1
Tennessee	4	764.3	106.0
Utah	1	5.64	0.294
Virginia	7	51.7	8.53
Washington	0		
West Virginia	3	719.4	91.4
Wisconsin	5	53.8	12.7
Wyoming	1	55.9	18.4
U.S. average	85	724.9	266.9

Note.—Blanks indicate no data were found.

TABLE B-2. RIVER FLOW RATE DATA (88-115)

State	County	City	Number of boilers	Rivers	Average river flow rate, m³/s	Minimum river flow rate, m³/s
Alabama	Morgan		1			
Georgia	Chattooga	Trion	4			
	Floyd	Rome	2	Etowah	94.9	19.6
Idaho	Bonneville	Idaho Falls	2	Snake	239.6	71.5
	Canyon	Nampa	2	Boise	61.6	2.8
	Minidoka	Rupert	2	Snake	263.0	76.5
	Twin Falls	Twin Falls	2	Snake	165.9	9.0
Illinois	Cook	Chicago Heights	3	Deer Creek	0.73	0.0096
	Franklin	Sesser	1	Big Muddy	27.4	1.13
	Fulton	Vermont	1			
	Grundy	Morris	1	Illinois	329.9	81.0
	Knox	Galesburg	1			
	Lake	North Chicago	1			
	Macon	Decatur	8	Sangamon	32.2	5.83
	Madison	Alton	2	Mississippi	3,714	843.8
	Peoria	Peoria	2	Illinois	573.1	58.0
	St. Clair	Belleville	3	Mississippi	6,199	2,272
	Will	Joliet	4	Hickory Creek	3.85	0.17
	Williamson	Johnson City	1			
Indiana	Clark	Charlestown	5			
	Clark	Jeffersonville	1			
	Lake	E. Chicago	5			
	Marion	Indianapolis	7	White	52.6	4.05
	St. Joseph	Mishawaka	3			
	Tippecanoe	Lafayette	1	Wabash	225.9	33.7
Iowa	Black Hawk	Waterloo	3	Cedar	101.7	20.5
	Cerro Gordo	Mason City	1	Winnebago	8.55	0.694
	Clinton	Clinton	5	Mississippi	1,392	516.8
	Des Moines	Burlington	1	Mississippi	1,392	516.8
	Lee	Fort Madison	1	Mississippi	2,268	637.1
	Muscatine	Muscatine	4	Mississippi	1,392	516.8
	Scott	Davenport	7	Mississippi	1,392	516.8
Kansas	Cherokee	Riverton	1			
Kentucky	Boyd	Leach	1			
		Cattlettsburg	1	Ohio	4,357	433.2
	Meade	Brandenburg	3	Ohio	5,450	3,079
	Muhlenberg	Madisonville	2			
Maryland	Allegany	Luke	2			
	Washington	Hagerstown	2			
Massachusetts		Billerica	1	Merrimack	248.6	41.1
Michigan	Calhoun	Battle Creek	3	Battle Creek	8.16	1.90
	Genesee	Flint	3	Flint	27.1	5.24
	Macomb		1			
	Midland	Midland	1	Tittubawassee	65.8	9.77
	Muskegon	Muskegon	3	Muskegon	69.5	29.9
	Ontonagon	Iron Mountain	4	Menominee	50.5	10.4
	Wayne	Detroit	7	River Rouge	2.83	0.481
	Wayne	Dearborn	7	River Rouge	4.67	0.453

(continued)

Note.—Blanks indicate no data were found.

TABLE B-2 (continued)

State	County	City	Number of boilers	Rivers	Average river flow rate, m³/s	Minimum river flow rate, m³/s
Minnesota	Anoka	Minneapolis	1	Mississippi	373.8	51.4
	Freeborn	Albert Lea	1			
Missouri	Pike	Louisiana	3			
	St. Louis	St. Louis	5	Mississippi	5,012	2,299
New York	Cattaraugus	Gowando	2	Cattaraugus Cr.	21.7	2.93
	Erie	Buffalo	1	Niagra	6.780	5,040
	Essex	Tahawus	1			
	Genesee	Oakfield	1			
	Jefferson	Carthage	1			
	Kings	New York	6			
	Monroe	Rochester	5	Genesee	90.8	13.3
	Niagra	Niagara Falls	2			
	Onondaga	Solvay	7			
	St. Lawrence	Heuvelton	1	Oswegatchie	50.7	7.76
	Schuyler	Watkins	1			
	Wayne	Palmyra	1			
North Carolina	Avery	Spruce Pine	1			
	Buncombe	Enka	4			
	Cabarrus	Concord	3			
	Davidson	Thomasville	2			
	Forsyth	Winston-Salem	4			
	Guilford	Greensboro	4	N. Buffalo Cr.	2.39	0.680
	Halifax	Roanoke Rapids	3	Roanoke	292.3	29.8
	Haywood	Canton	4			
	Iredell	Mooresville	2			
	McDowell	Marion	3	Catawba	12.9	4.50
	McDowell	Old Fort	3	Catawba	12.9	4.50
	Polk	Tryon	1			
	Rockingham	Reidsville	4			
	Rowan	Salisbury	1	Yadkin	107.7	43.7
	Transylvania		3			
Ohio	Butler	Hamilton	7	Great Miami	116.5	19.9
	Cuyahoga	Cleveland	12	Cuyahoga		
	Franklin	Columbus	4	Scioto	49.5	3.96
	Hamilton	Cincinnati	10	Ohio	6,075	3,308
	Jefferson	Steubenville	10	Ohio		
	Lake	Painesville	4			
	Lawrence	Ironton	2	Ohio		
	Mahoning	Youngstown	12	Mahoning	41.4	8.69
	Montgomery	Dayton	8	Great Miami	77.9	11.4
	Stark	Canton	7	Nihishillen Cr.	1.70	0.283
	Summit	Akron	6	Little Cuyahoga	17.2	2.89
	Trumbull	Warren	1	Mahoning	26.5	6.17
	Tuscarawas	Dover	2	Tuscarawas	61.9	9.71
Oregon	Malheur	Nyssa	3	Snake	538.3	442.2
Pennsylvania	Adams		3			
	Allegheny	McKeesport	4	Monongahela	420.1	56.6
	Allegheny	Trafford	1			
	Allegheny	Bridgeville	1	Chartiers Cr.	10.2	2.21
	Allegheny	Braddock	3	Monongahela	420.1	56.6
	Allegheny	Homestead	2	Monongahela	420.1	56.6

Note.—Blanks indicate no data were found.

(continued)

TABLE B-2 (continued)

State	County	City	Number of boilers	Rivers	Average river flow rate, m³/s	Minimum river flow rate, m³/s
Pennsylvania (continued)	Allegheny	Clairston	1	Monongahela	305.8	21.7
	Allegheny	Pittsburgh	2	Ohio	1,084	139.9
	Armstrong	Kittanning	3	Allegheny	519.0	70.8
	Beaver	Monaca	4	Ohio	1,084	139.9
	Beaver	Midland	1	Ohio	1,084	139.9
	Blair	Tyrone	2	Bald Eagle Cr.	2.05	0.0850
	Butler		4			
	Crawford	Meadville	4	French Cr.	60.6	5.75
	Cumberland	Carlisle	1			
	Dauphin	Hershey	5			
	Elk	Johnsonburg	1	Clarion	13.6	4.13
	Erie	Erie	4			
	McKean	Bradford	3			
	Washington	Monessen	6	Monongahela	305.8	21.7
Tennessee	Davidson	Old Hickory	5	Cumberland	794.1	48.6
	Davidson	Nashville	1	Cumberland	794.1	48.6
	Hamblen	Lowland	7			
	Hamilton	Chattanooga	1	Tennessee	1,355	304.4
	Hawkins	Kingsport	11	S. Fork, Holston	113.8	22.2
	Washington	Johnson City	1			
Utah	Salt Lake	Magna	3	Coggin Drain	5.64	0.294
	Utah	Geneva	3			
Virginia	Alleghany	Covington	2	Jackson	23.6	3.31
	Augusta	Waynesboro	5	South	4.02	0.934
	Bedford		1			
	Buckingham	Arvonia	1	Slate	9.20	1.87
	Campbell	Lynchburg	1			
	Chesterfield	Richmond	1	James	216.9	28.5
	Giles	Narrows	4	Wolf Creek	10.8	1.08
	Henry	Martinsville	2	Smith	14.6	2.75
	Montgomery		2			
	Pittsylvania	Danville	1	Dan	83.1	21.3
	Pulaski	Pulaski	1			
	Warren	Front Royal	2			
	Wise	Norton	1			
Washington	Yakima	Toppenish	1			
West Virginia	Brooke	Follansbee	3	Ohio	1,084	139.9
	Kanawha	South Charleston	8	Kanawha	536.9	67.1
	Kanawha	Institute	8	Kanawha	536.9	67.1
Wisconsin	Chippewa	Cornell	1	Chippewa	44.2	16.4
	Eau Clair	Eau Clair	2	Chippewa	137.7	14.4
	Marinette	Niagra	3	Menominee	80.8	32.0
	Racine	Racine	1	Root	4.98	0.153
	Wood	Nekoosa	2	Ten Mile Cr.	1.50	0.651
Wyoming	Sweetwater	Green River	2	Green	55.9	18.4

Note.—Blanks indicate no data were found.

APPENDIX C

DESCRIPTION OF THE SAMPLING PROGRAM

Emissions data in the literature for this source are often presented under titles such as industrial boilers, pulverized coal fired boilers, intermediate size combustion equipment, etc., thus obscuring the relationship of the data to this source type as defined in Section 3. In order to verify the literature data and emissions estimates in this report, and to determine emission values for species previously unaddressed in sufficient detail for this source type, a program was designed to provide the necessary information by conducting sampling of one typical source.

SITE DESCRIPTION

The boiler chosen for sampling was a horizontally fired, dry bottom unit burning pulverized Appalachian bituminous coal to produce steam for process and space heating at an industrial site. The boiler has a rated firing capacity of 130 GJ/hr (123 MBTU/hr) and an output capacity of 45,000 kilograms of steam per hour (100,000 lb steam/hr). This value is somewhat below the minumum capacity limit for economic utilization of pulverized coal which is frequently cited in the literature (200 MBTU/hr).[a] Our reasons for choosing a boiler in this size range are twofold: 1) approximately 64% of the industrial boilers included in this source type are smaller than the above mentioned limit according to NEDS data (5), and 2) boilers in this size range have the potential for higher emission levels than do larger units owing to decreased usage of environmental controls and decreased combustion efficiency.

Air emissions from coal combustion are controlled by a high efficiency electrostatic precipitator and are discharged through a 53 m stack. The path of the flue gas flow is from the furnace to the ESP, to an air preheater, to the stack. The boiler is fired with a low-sulfur Appalachian bituminous coal. Ultimate and trace element analysis conducted on coal samples obtained during the sampling period are shown in Table C-1.

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[a] At the site sampled, there are additional pulverized coal fired boilers sharing the auxiliary equipment necessary for pulverized coal usage and resulting in a total capacity above the given lower limit.

TABLE C-1. ANALYSIS OF COAL FIRED IN BOILER SAMPLED

Analysis	Unit	Average value[a]	Analysis	Unit	Average value[a]
Moisture	%	8.4	Elements (cont'd):		
Ash	%	8.2	Copper	g/kg of coal	0.044
Heating value[b]	MJ/kg	28.78	Iron	g/kg of coal	1.8
Carbon	%	71.6	Lead	g/kg of coal	0.012
Nitrogen	%	1.6	Magnesium	g/kg of coal	0.32
Hydrogen	%	5.0	Manganese	g/kg of coal	0.013
Sulfur	%	0.91	Mercury	g/kg of coal	0.0005
Sulfate	%	0.09	Molybdenum	g/kg of coal	0.0085
Elements:			Nickel	g/kg of coal	0.0042
Aluminum	g/kg of coal	5.8	Phosphorus	g/kg of coal	0.088
Antimony	g/kg of coal	0.016	Selenium	g/kg of coal	0.001
Arsenic	g/kg of coal	0.0069	Silicon	g/kg of coal	0.11
Barium	g/kg of coal	0.054	Silver	g/kg of coal	0.0062
Beryllium	g/kg of coal	0.0044	Sodium	g/kg of coal	0.34
Boron	g/kg of coal	0.013	Strontium	g/kg of coal	0.068
Cadmium	g/kg of coal	0.0014	Tin	g/kg of coal	0.02
Calcium	g/kg of coal	0.72	Titanium	g/kg of coal	0.37
Chromium	g/kg of coal	0.016	Vanadium	g/kg of coal	0.078
Cobalt	g/kg of coal	0.072	Zinc	g/kg of coal	0.019
			Zirconium	g/kg of coal	

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[a] Average of two to three analyses on each of three samples.

[b] On as-received basis.

[c] Not detected.

On-site water requirements are met using municipal drinking water. Daily wastewater streams result from boiler blowdown, feedwater treatment using ion exchange, and once-through cooling water for fan bearings. Fly ash from the ESP is pneumatically conveyed to a hopper by a vacuum created by condensing steam. The resultant wastewater discharge consists of the condensate and any material picked up or leached from contacting the fly ash. Fireside and waterside boiler cleaning, which result in an additional wastewater stream, are performed once each year. All wastewaters are discharged to a municipal sewer.

The bottom ash and precipitation ash are both handled dry, and they constitute the only source of solid waste. Air emissions from ash handling are controlled by wetting the ash prior to its transport to a landfill site.

AIR SAMPLING PROCEDURE

Air emissions from the inlet and outlet ducts of the ESP were sampled for particulate loading, particulate size, PCB, POM, carbon monoxide, hydrocarbons, sulfur oxides, particulate sulfate and trace metals.

Particulate mass emission rates were determined using the EPA Method 5 procedure (138). Each duct was sampled at 33 points on three levels. Samples were collected isokinetically for five minutes at each point. Before each run, the sampling train was checked for leaks by plugging the inlet to the filter holder and pulling a vacuum. A leakage rate of less than 9.4×10^{-6} m^3/s at a vacuum of 50.8 kPa was considered acceptable. After each run, the probe and nozzle were handled in accordance with appropriate sample recovery procedures.

Particle size data and samples for PCB, POM, and elemental analyses were collected using a Source Assessment Sampling System (SASS) train. This train, depicted in Figure C-1, employs a set of three cyclones for particulate size fractionation, a solid sorbent trap utilizing XAD-2 resin for organic collection, an impinger collection trap for trace inorganics, and a system for flow measurement and gas pumping (139). The impinger portion of the train consists of four impingers whose order, contents, and purpose are shown in Table C-2 (139). The sampling and analysis

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(138) Method 5 - Determination of Particulate Emissions from Stationary Sources. Federal Register, 41(111):23076-23083, 1976.

(139) Hamersma, J. W., S. L. Reynolds, and R. F. Maddalone. IERL-RTP Procedure Manual: Level I Environmental Assessment. EPA-600/2-76-160a (PB 257 850), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, June 1976. 131 pp.

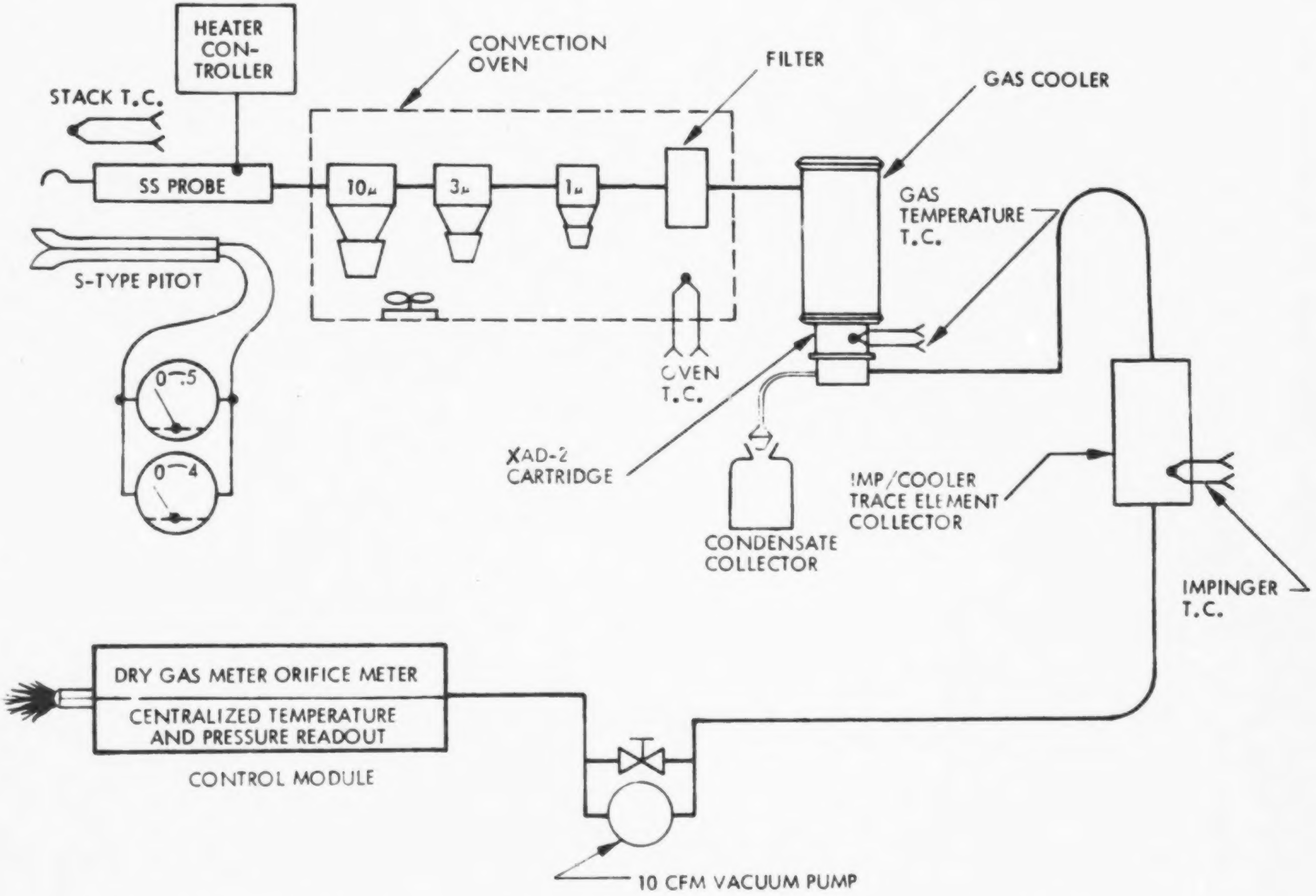
HEATER CON- TROLLER
STACK T.C.
SS PROBE
S-TYPE PITOT
0—.5
0—4
CONVECTION OVEN
10μ
3μ
1μ
FILTER
OVEN T.C.
GAS COOLER
GAS TEMPERATURE T.C.
XAD-2 CARTRIDGE
CONDENSATE COLLECTOR
IMP/COOLER TRACE ELEMENT COLLECTOR
IMPINGER T.C.
DRY GAS METER ORIFICE METER
CENTRALIZED TEMPERATURE AND PRESSURE READOUT
CONTROL MODULE
10 CFM VACUUM PUMP

Figure C-1. Source Assessment Sampling System train (139).

procedures used on this project, as described in Reference 139, have since been modified (140).

TABLE C-2. SASS TRAIN IMPINGER SYSTEM REAGENTS (139)

Impinger	Reagent	Quantity	Purpose
1	6M H_2O_2	750 ml	Trap reducing gases such as SO_2 to prevent depletion of oxidative capability of trace-element collection impingers 2 and 3.
2	0.2M $(NH_4)_2S_2O_8$ + 0.02M $AgNO_3$	750 ml	Collect volatile trace elements by oxidative dissolution.
3	0.2M $(NH_4)_2S_2O_8$ + 0.02M $AgNO_3$	750 ml	Collect volatile trace elements by oxidative dissolution.
4	Drierite (color indicating)	750 g	Prevent moisture from reaching pumps.

Prior to operating the SASS train, a velocity traverse and moisture determination were completed at each sampling location using EPA Method 2 (141) and Method 4 (142). These methods were employed to determine the point of average velocity and to characterize the source to an extent sufficient for operating the sampling system as close to isokinetic conditions as possible within the available nozzle sizes and operating parameters.

Preparation and operation of the SASS train was conducted as outlined in the IERL-RTP Procedures Manual (139). In brief, the presampling cleaning included passivation of all sample surfaces with aqueous nitric acid (50% by volume). All samples associated with the collection of organics were subsequently cleaned with distilled water, isopropyl alcohol, and methylene chloride, in succession. The impinger portion, used for inorganic collection, was cleaned with distilled water followed by isopropyl alcohol.

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(140) Lentzen, D. E., D. E. Wagoner, E. D. Estes, and W. F. Gutknecht. IERL-RTP Procedures Manual: Level 1 Environmental Assessment (Second Edition). EPA-600/7-78-201, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, October 1978. 279 pp.

(141) Method 2 - Determination of Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tube). Federal Register, 41(111):23063-23069, 1976.

(142) Method 4 - Determination of Moisture in Stack Gases. Federal Register, 41(111):23072-23076, 1976.

At the sampling site, the SASS train was assembled and checked for leak after heating the oven to 205¼C while maintaining the organic resin trap at 20°C. A leak rate of less than 2.36×10^{-5} m^3/s at 67.6 kPa was considered acceptable. After passing the leak check, the probe tip was attached, the impingers were filled, and sampling was begun using a rate of 1.4×10^{-3} to 2.4×10^{-3} m^3/s at the dry test meter. Each SASS train run was conducted for a period in excess of five hours in order to collect approximately 30 m^3. Cleanup procedures used after each run were those specified in the procedures manual (139) and shown graphically in Figures C-2 through C-4.

Sulfur dioxide, sulfur trioxide (acid mist), and particulate sulfate emissions were measured using a procedure based on EPA Method 8 (143). The Method 8 train was modified to allow collection of particulate sulfate by inserting a filter between the probe and the first impinger and maintaining it at a temperature (∿150°C) sufficient to volatilize sulfuric acid mist. Sampling was then conducted at isokinetic conditions. At the conclusion of each run, the filter was placed in a petri dish and sealed. The probe and front half of the filter holder were washed with distilled water which was then bottled. Post-sampling treatment of the rest of the train and samples followed the normal procedures in Method 8.

Carbon monoxide was determined by the direct analysis of the gas stream using a Bendix tube calibrated for 0 ppm to 50 ppm of CO. Low-molecular-weight hydrocarbons (C_1 to C_6) were sampled by collecting integrated gas samples in Tedlar bags. The bag contents were then analyzed within 24 hours using gas chromatography. Integrated gas samples were also collected for carbon dioxide, excess air, and dry molecular weight determinations using EPA Method 3 (144).

PROCEDURE FOR SAMPLING EFFLUENTS

Samples of the wastewater streams from boiler blowdown, cooling of the fan bearing, boiler feedwater treatment, pneumatic ash transport steam wash, and the water source were composited on an

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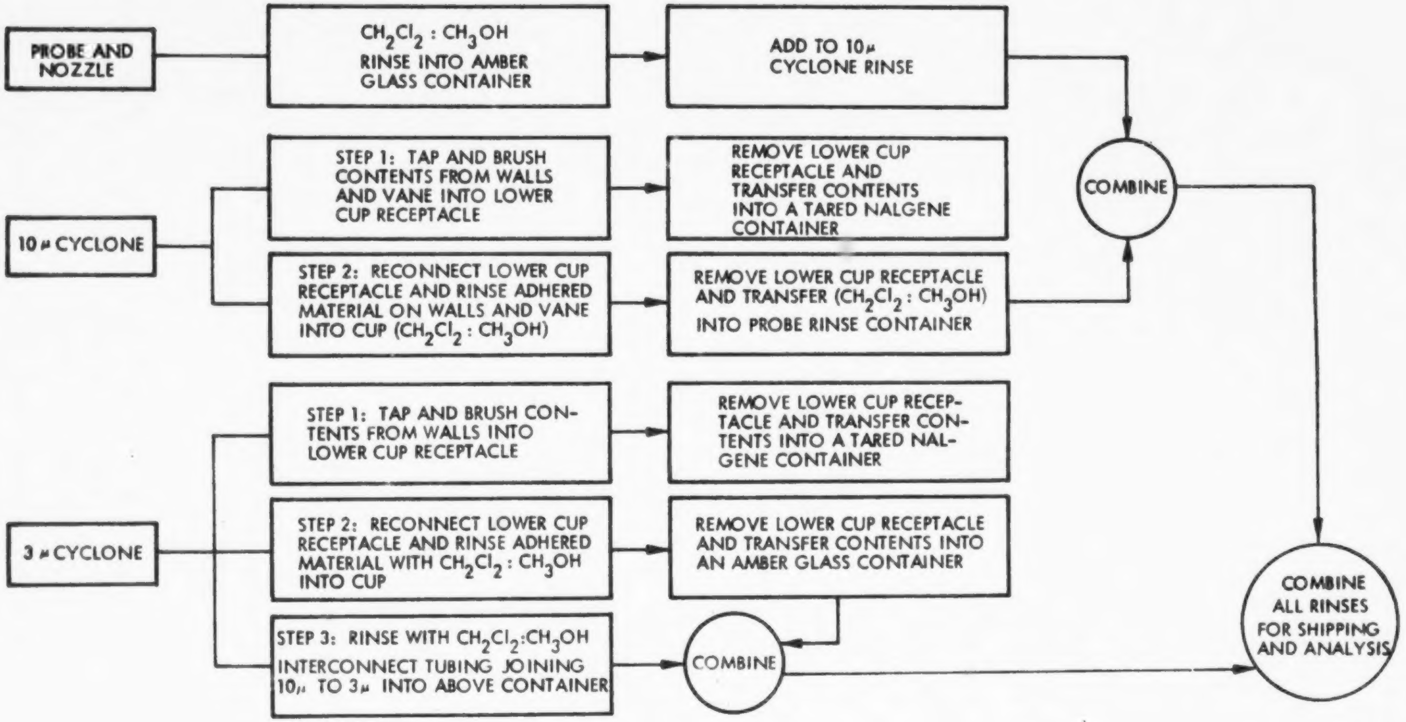
(143) Method 8 - Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sources. Federal Register, 41(111):23087-23090, 1976.

(144) Method 3 - Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight. Federal Register, 41(111): 23069-23070, 1976.



PROBE AND NOZZLE
$CH_2Cl_2 : CH_3OH$ RINSE INTO AMBER GLASS CONTAINER
ADD TO 10μ CYCLONE RINSE
10μ CYCLONE
STEP 1: TAP AND BRUSH CONTENTS FROM WALLS AND VANE INTO LOWER CUP RECEPTACLE
REMOVE LOWER CUP RECEPTACLE AND TRANSFER CONTENTS INTO A TARED NALGENE CONTAINER
STEP 2: RECONNECT LOWER CUP RECEPTACLE AND RINSE ADHERED MATERIAL ON WALLS AND VANE INTO CUP ($CH_2Cl_2 : CH_3OH$)
REMOVE LOWER CUP RECEPTACLE AND TRANSFER ($CH_2Cl_2 : CH_3OH$) INTO PROBE RINSE CONTAINER
COMBINE
3μ CYCLONE
STEP 1: TAP AND BRUSH CONTENTS FROM WALLS INTO LOWER CUP RECEPTACLE
REMOVE LOWER CUP RECEPTACLE AND TRANSFER CONTENTS INTO A TARED NALGENE CONTAINER
STEP 2: RECONNECT LOWER CUP RECEPTACLE AND RINSE ADHERED MATERIAL WITH $CH_2Cl_2 : CH_3OH$ INTO CUP
REMOVE LOWER CUP RECEPTACLE AND TRANSFER CONTENTS INTO AN AMBER GLASS CONTAINER
STEP 3: RINSE WITH $CH_2Cl_2:CH_3OH$ INTERCONNECT TUBING JOINING 10μ TO 3μ INTO ABOVE CONTAINER
COMBINE
COMBINE ALL RINSES FOR SHIPPING AND ANALYSIS

Figure C-2. Sample handling and transfer: nozzle, probe, cyclones, and filter (139).

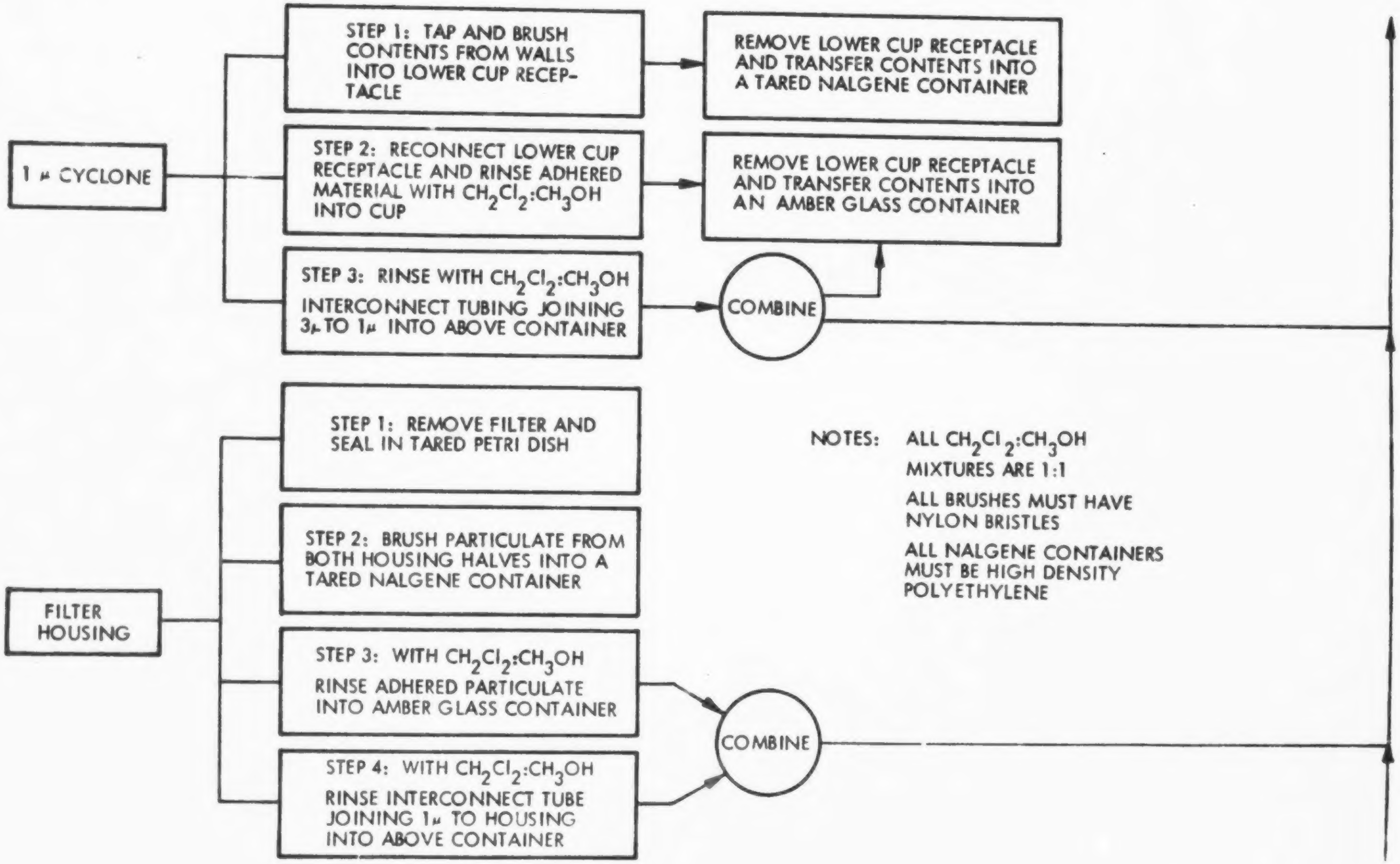

1 µ CYCLONE
STEP 1: TAP AND BRUSH CONTENTS FROM WALLS INTO LOWER CUP RECEPTACLE
STEP 2: RECONNECT LOWER CUP RECEPTACLE AND RINSE ADHERED MATERIAL WITH CH_2Cl_2:CH_3OH INTO CUP
STEP 3: RINSE WITH CH_2Cl_2:CH_3OH INTERCONNECT TUBING JOINING 3µ TO 1µ INTO ABOVE CONTAINER
REMOVE LOWER CUP RECEPTACLE AND TRANSFER CONTENTS INTO A TARED NALGENE CONTAINER
REMOVE LOWER CUP RECEPTACLE AND TRANSFER CONTENTS INTO AN AMBER GLASS CONTAINER
COMBINE
FILTER HOUSING
STEP 1: REMOVE FILTER AND SEAL IN TARED PETRI DISH
STEP 2: BRUSH PARTICULATE FROM BOTH HOUSING HALVES INTO A TARED NALGENE CONTAINER
STEP 3: WITH CH_2Cl_2:CH_3OH RINSE ADHERED PARTICULATE INTO AMBER GLASS CONTAINER
STEP 4: WITH CH_2Cl_2:CH_3OH RINSE INTERCONNECT TUBE JOINING 1µ TO HOUSING INTO ABOVE CONTAINER
COMBINE
NOTES: ALL CH_2Cl_2:CH_3OH MIXTURES ARE 1:1
ALL BRUSHES MUST HAVE NYLON BRISTLES
ALL NALGENE CONTAINERS MUST BE HIGH DENSITY POLYETHYLENE

Figure C-2. (continued) (139).

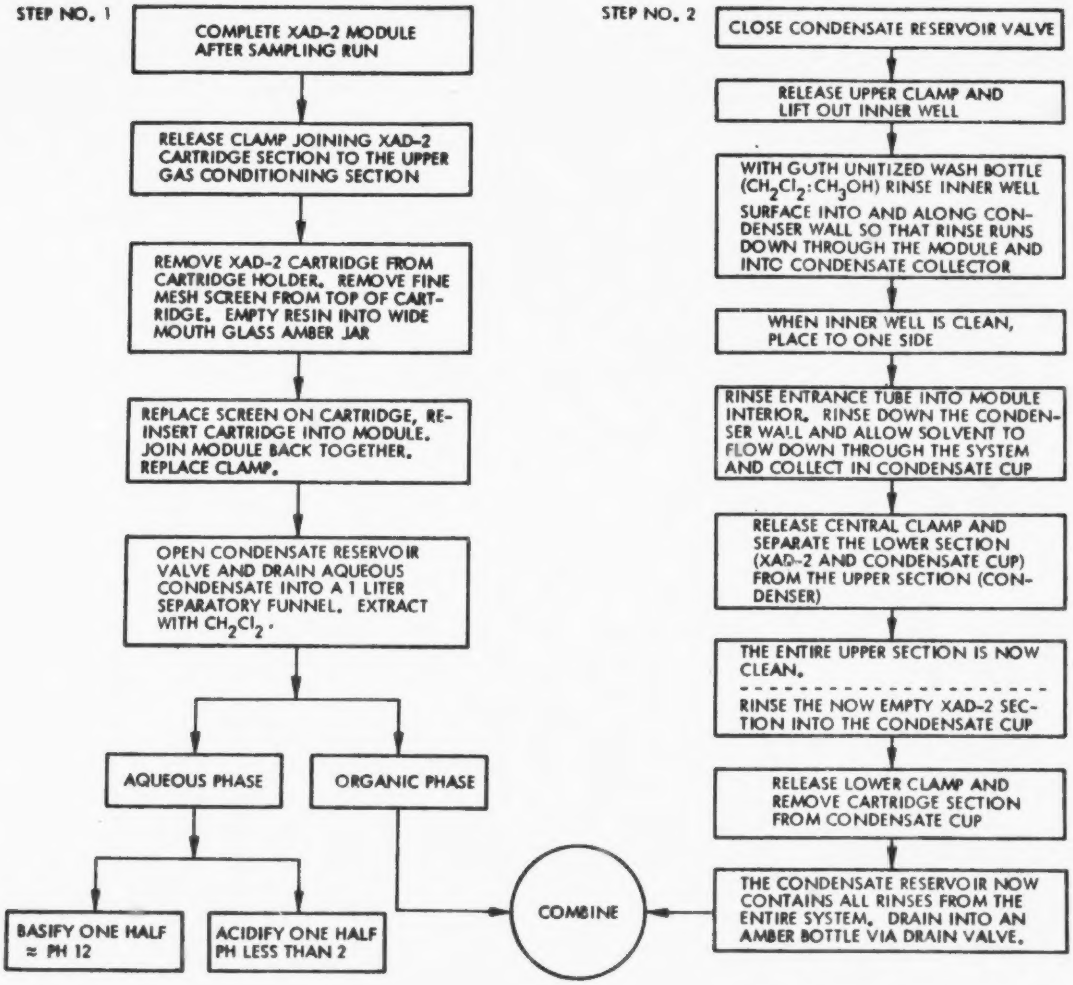

STEP NO. 1
COMPLETE XAD-2 MODULE AFTER SAMPLING RUN
RELEASE CLAMP JOINING XAD-2 CARTRIDGE SECTION TO THE UPPER GAS CONDITIONING SECTION
REMOVE XAD-2 CARTRIDGE FROM CARTRIDGE HOLDER. REMOVE FINE MESH SCREEN FROM TOP OF CARTRIDGE. EMPTY RESIN INTO WIDE MOUTH GLASS AMBER JAR
REPLACE SCREEN ON CARTRIDGE, REINSERT CARTRIDGE INTO MODULE. JOIN MODULE BACK TOGETHER. REPLACE CLAMP.
OPEN CONDENSATE RESERVOIR VALVE AND DRAIN AQUEOUS CONDENSATE INTO A 1 LITER SEPARATORY FUNNEL. EXTRACT WITH CH_2Cl_2.
AQUEOUS PHASE
ORGANIC PHASE
BASIFY ONE HALF ≈ PH 12
ACIDIFY ONE HALF PH LESS THAN 2
COMBINE
STEP NO. 2
CLOSE CONDENSATE RESERVOIR VALVE
RELEASE UPPER CLAMP AND LIFT OUT INNER WELL
WITH GUTH UNITIZED WASH BOTTLE ($CH_2Cl_2:CH_3OH$) RINSE INNER WELL SURFACE INTO AND ALONG CONDENSER WALL SO THAT RINSE RUNS DOWN THROUGH THE MODULE AND INTO CONDENSATE COLLECTOR
WHEN INNER WELL IS CLEAN, PLACE TO ONE SIDE
RINSE ENTRANCE TUBE INTO MODULE INTERIOR. RINSE DOWN THE CONDENSER WALL AND ALLOW SOLVENT TO FLOW DOWN THROUGH THE SYSTEM AND COLLECT IN CONDENSATE CUP
RELEASE CENTRAL CLAMP AND SEPARATE THE LOWER SECTION (XAD-2 AND CONDENSATE CUP) FROM THE UPPER SECTION (CONDENSER)
THE ENTIRE UPPER SECTION IS NOW CLEAN.
RINSE THE NOW EMPTY XAD-2 SECTION INTO THE CONDENSATE CUP
RELEASE LOWER CLAMP AND REMOVE CARTRIDGE SECTION FROM CONDENSATE CUP
THE CONDENSATE RESERVOIR NOW CONTAINS ALL RINSES FROM THE ENTIRE SYSTEM. DRAIN INTO AN AMBER BOTTLE VIA DRAIN VALVE.

Figure C-3. Sampling handling and transfer: XAD-2 module (139).

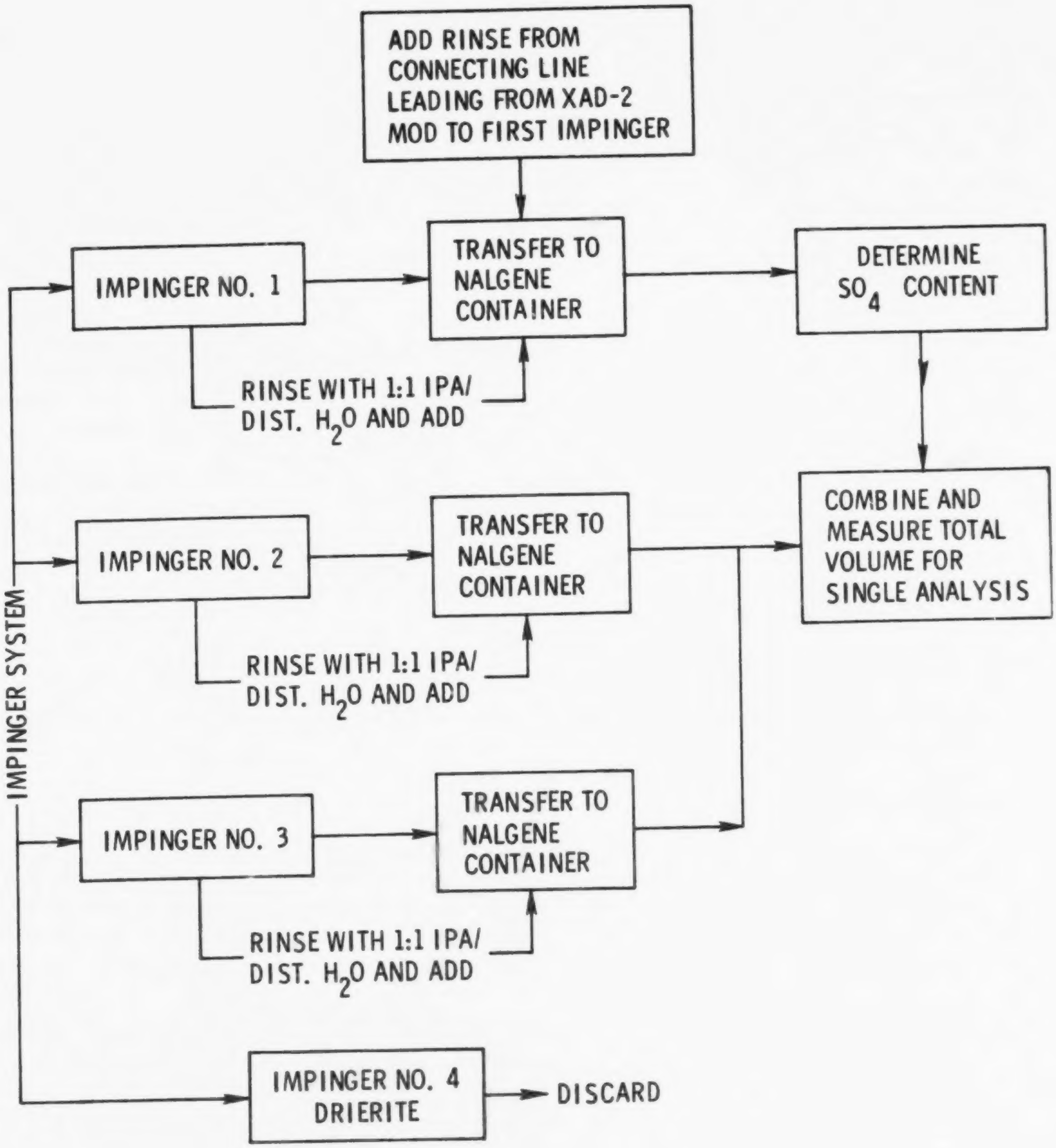

ADD RINSE FROM CONNECTING LINE LEADING FROM XAD-2 MOD TO FIRST IMPINGER
IMPINGER SYSTEM
IMPINGER NO. 1
TRANSFER TO NALGENE CONTAINER
RINSE WITH 1:1 IPA/ DIST. H_2O AND ADD
DETERMINE SO_4 CONTENT
IMPINGER NO. 2
TRANSFER TO NALGENE CONTAINER
RINSE WITH 1:1 IPA/ DIST. H_2O AND ADD
COMBINE AND MEASURE TOTAL VOLUME FOR SINGLE ANALYSIS
IMPINGER NO. 3
TRANSFER TO NALGENE CONTAINER
RINSE WITH 1:1 IPA/ DIST. H_2O AND ADD
IMPINGER NO. 4 DRIERITE
DISCARD

Figure C-4. Sample handling and transfer: impingers (139).

hourly basis for eight hours. Table C-3 provides information on the bottles, preservatives, and sample volumes used in sampling each stream.

PROCEDURE FOR SAMPLING SOLIDS

Bottom ash and precipitator ash samples were collected and composited according to the procedure provided for fly ash sampling in ASTM C 311-68 (145). Three samples of the coal feed were obtained employing the procedure given in ASTM D 2234-72, "Collection of a Gross Sample of Coal" (146).

ANALYTICAL PROCEDURES

Field samples which required laboratory analysis include those from the EPA Method 5 train for particulate loading; the SASS train for particle sizing, organic analysis (hydrocarbons greater than C_7, POM, and PCB), and trace element analysis; the modified EPA Method 8 train for sulfur dioxide, sulfur trioxide, and particulate sulfate; the integrated gas samples for C_1 to C_6 hydrocarbons; and the wastewater, fly ash, and coal samples for a variety of analyses. Handling and analytical procedures used for these samples are described below; however, descriptions of the procedures used for the organic and elemental analyses are deferred until the end of this appendix because they involve air, water, and solid samples.

Particulate Loading

Particulate loading was determined using the procedure described in EPA Method 5 (138).

SASS Train Samples

The separation and analysis of the SASS train samples is depicted in Figure C-5 and, in general, follows the methods employed for Level I type analysis. These methods are briefly outlined below. The procedures described here have since been modified, as noted in Reference 140.

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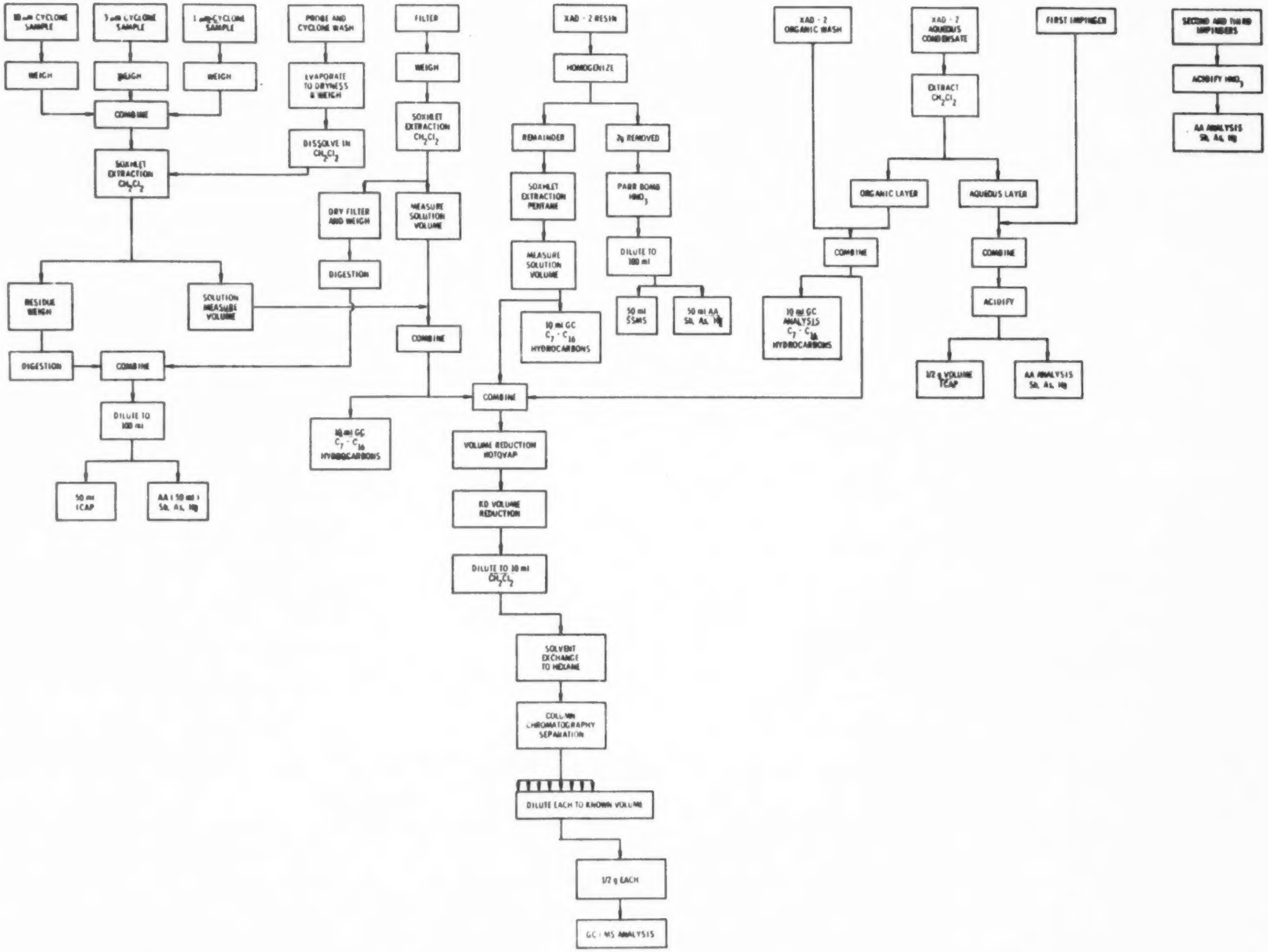
(145) Standard Methods of Sampling and Testing Fly Ash for Use as an Admixture in Portland Cement Concrete, Designation C 311-68. In: 1972 Annual Book of ASTM Standards, Part 10: Concrete and Mineral Aggregates. American Society for Testing and Materials, Philadelphia, Pennsylvania, 1972. pp. 220-226.

(146) Standards Methods of Collection of a Gross Sample of Coal, Designation D 2234-72. In: 1973 Annual Book of ASTM Standards, Part 19: Gaseous Fuels; Coal and Coke. American Society for Testing and Materials, Philadelphia, Pennsylvania, 1973. pp. 355-371.

TABLE C-3. BASIC INFORMATION FOR PREPARATION OF 8-HOUR COMPOSITE SAMPLES OF WATER AND WASTEWATER STREAMS

Analysis to be performed:	PCB; POM	Trace elements	NH_3; COD; NO_3	TSS TDS TS	Phenol	Sulfite
Type of sample bottle:	1 gal glass	1/2 gal plastic	1/2 gal plastic	1/2 gal plastic	500 ml glass	500 ml glass
Hourly period:	Sample size to be taken and preservatives to be added					
1	add 470 ml	add 240 ml add 5 ml HNO_3	add 240 ml[a] H_2SO_4, pH<	add 240 ml	add 62 ml pH<4 w/H_3PO_4	add 62 ml
2	add 470 ml	add 240 ml	add 240 ml H_2SO_4, pH<2	add 240 ml	add 62 ml add 0.5g $CuSO_4$	add 62 ml
3	add 470 ml	add 240 ml	add 240 ml H_2SO_4, pH<2	add 240 ml	add 62 ml	add 62 ml
4	add 470 ml	add 240 ml add 5 ml HNO_3	add 240 ml H_2SO_4, pH<2	add 240 ml	add 62 ml pH<4 w/H_3PO_4	add 62 ml
5	add 470 ml	add 240 ml	add 240 ml H_2SO_4, pH<2	add 240 ml	add 62 ml	add 62 ml
6	add 470 ml	add 240 ml	add 240 ml H_2SO_4, pH<2	add 240 ml	add 62 ml	add 62 ml
7	add 470 ml	add 240 ml	add 240 ml H_2SO_4, pH<2	add 240 ml	add 62 ml	add 62 ml
8	add 470 ml seal	add 240 ml seal	add 240 ml H_2SO_4, pH<2 seal	add 240 ml seal	add 62 ml pH<4 w/H_3PO_4 seal	add 62 ml seal

[a] H_2SO_4 must be added to adjust the pH to a value <2.



10 μm CYCLONE SAMPLE
3 μm CYCLONE SAMPLE
1 μm CYCLONE SAMPLE
PROBE AND CYCLONE WASH
FILTER
XAD - 2 RESIN
XAD - 2 ORGANIC WASH
XAD - 2 AQUEOUS CONDENSATE
FIRST IMPINGER
SECOND AND THIRD IMPINGERS
WEIGH
WEIGH
WEIGH
EVAPORATE TO DRYNESS & WEIGH
WEIGH
HOMOGENIZE
EXTRACT CH_2Cl_2
ACIDIFY HNO_3
COMBINE
DISSOLVE IN CH_2Cl_2
SOXHLET EXTRACTION CH_2Cl_2
REMAINDER
2g REMOVED
AA ANALYSIS Sb, As, Hg
SOXHLET EXTRACTION CH_2Cl_2
DRY FILTER AND WEIGH
MEASURE SOLUTION VOLUME
SOXHLET EXTRACTION PENTANE
PARR BOMB HNO_3
ORGANIC LAYER
AQUEOUS LAYER
DIGESTION
MEASURE SOLUTION VOLUME
DILUTE TO 100 ml
COMBINE
COMBINE
RESIDUE WEIGH
SOLUTION MEASURE VOLUME
50 ml SSMS
50 ml AA Sb, As, Hg
10 ml GC ANALYSIS C_7 - C_{16} HYDROCARBONS
ACIDIFY
COMBINE
10 ml GC C_7 - C_{16} HYDROCARBONS
DIGESTION
COMBINE
COMBINE
1/2 g VOLUME ICAP
AA ANALYSIS Sb, As, Hg
DILUTE TO 100 ml
10 ml GC C_7 - C_{16} HYDROCARBONS
VOLUME REDUCTION ROTOVAP
50 ml ICAP
AA (50 ml) Sb, As, Hg
KD VOLUME REDUCTION
DILUTE TO 10 ml CH_2Cl_2
SOLVENT EXCHANGE TO HEXANE
COLUMN CHROMATOGRAPHY SEPARATION
DILUTE EACH TO KNOWN VOLUME
1/2 g EACH
GC / MS ANALYSIS

Figure C-5. Separation and analysis scheme: SASS train samples.

Cyclone Collected Material--
Cyclone materials were weighed separately to provide particulate size data. After weighing, the cyclone contents were combined into one sample and extracted for 24 hours with methylene chloride. This is a deviation from the Level I procedure in which a portion is removed prior to extraction for trace element analysis. After extraction, the residue (unextractables) in the thimble was reweighed and then digested for trace element analysis. For this type sample, the solid was digested in a HNO_3-perchloric acid medium because fly ash is difficult to digest using the normal Parr bomb technique. The volume of the liquid from the Soxhlet extraction was measured and the liquid was combined with the extracted portions of the filter.

Probe and Cyclone Washes--
The methylene chloride-methanol washings of the probe, cyclones, and filter holder were evaporated to dryness and weighed. The dry material was then dissolved in methylene chloride and transferred quantitatively to the Soxhlet extraction apparatus along with the cyclone collected material.

Filter--
The filter from the SASS train was dried and weighed, and the weight was combined with the cyclone collection and washing from the "front" portion of the train. The filter was then Soxhlet extracted for 24 hours with methylene chloride. The filter was dried and weighed, and the volume of the extraction solution was measured. This solution was combined with the cyclone extraction solution, and a 1-ml to 10-ml portion was withdrawn for GC analysis of C_7 to C_{16} hydrocarbons. The remaining solution was combined with the XAD-2 resin extract and the organic washing of the XAD-2 resin trap. The filter and nonextractable residue were digested using Parr bomb and HNO_3-perchloric acid digestion. The resulting solution was separated from the filter remains and combined with the solution from the cyclone material digestion.

XAD-2 Resin--
The resin was stirred to mix the sample thoroughly, and a 2-gram portion was removed and digested in the Parr bomb with nitric acid. Digested materials were diluted to a known volume and divided for the various trace element analyses. Remaining XAD-2 resin (about 250 grams) was Soxhlet extracted for 24 hours with pentane. The volume was measured and a 1-ml to 10-ml portion was withdrawn for GC analysis of the C_7 to C_{16} hydrocarbons. Remaining solution was combined with the methylene chloride extraction material from the cyclones and filters, and the organic wash from the resin trap.

First Impinger Contents, XAD-2 Trap Organic Wash, and Aqueous Condensate--
Aqueous condensate from the resin trap was extracted with methylene chloride, and the organic portion was combined with the

methylene chloride wash of the trap. The volume was measured and a 1-ml to 10-ml aliquot was removed for GC analysis of the C_7 to C_{16} hydrocarbons. The remaining solution was combined with the XAD-2 resin, filter, and particulate extracts prior to volume reduction and liquid chromatography fractionation. Remaining aqueous layers were combined with the liquid from the first impinger, and the solution was acidified and divided for trace element analysis.

Second and Third Impingers--

Contents of the second and third impingers were acidified and analyzed using atomic absorption for mercury, antimony, arsenic, selenium, beryllium, and zirconium.

Sulfur Oxides, Sulfuric Acid and Particulate Sulfate--

Samples for sulfur analysis, collected by the modified Method 8 sampling system, consist of the particulate filter, the first impinger (isopropanol), the filter between the impingers, and the second and third impingers (hydrogen peroxide). Procedures described in Method 8 were employed for the analysis of the impingers and the filter between impingers; that is, titration with barium perchlorate using Thorin indicator (143). Analysis of the particulate filter required digestion of the material on the filter using a combination of nitric and perchloric acids in order to oxidize and dissolve the fly ash. Following digestion, the sample was analyzed for sulfate content using a gravimetric procedure involving barium nitrate to precipitate the sulfate as barium sulfate.

C_1 to C_6 Hydrocarbons

Gaseous hydrocarbons in the C_1 to C_6 range were analyzed by gas chromatography using a flame ionization detector (FID). A stainless steel column, packed with Poropak Q and operated isothermally at 50°C, was used for the separation.

Determination of Water Quality Parameters

Laboratory determination of water quality parameters followed the methods outlined in the APHA Standard Methods (147) with the exception of ammonia, which was determined by an ion-selective electrode method. Table C-4 lists the analyses, the method selected, and the page number on which if may be found in the reference cited.

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(147) Standard Methods for the Examination of Water and Wastewater, 13th Edition; M. J. Taras, A. E. Greenberg, R. D. Doak, and M. C. Rand, eds. American Public Health Association, New York, New York, 1971. 874 pp.

TABLE C-4. METHODS FOR WATER QUALITY ANALYSIS (147)

Parameter	Method no.	Page no. in Ref. 147
Acidity	101	50-52
Alkalinity	102	52-56
Hardness	122A	179
COD	220	495-499
pH	144A	276-280
Nitrate	133A	234-237
Total solids	224A and B	535-536
Total dissolved solids	224E	539
Total suspended solids	224C	537-538
Oil and grease	137	254-256
Sulfate	156	330-333
Sulfite	158	337-338

Coal Samples

Three samples of the coal feed were analyzed for moisture content, ash, heating value, carbon-hydrogen-nitrogen content, sulfur, sulfate and trace metals. These analyses were conducted employing ASTM standard methods (148, 149). Trace metal analyses were conducted after acid digestion employing the Parr 4745 Teflon-lined bomb technique.

Ash Samples

Samples of bottom ash and precipitator ash were composited and artificially leached with distilled deionized water by shaking the ash-water mixture for one week. The leachate was then separated using filtration and analyzed for organics and trace elements. Samples of both ashes were also digested separately and analyzed for trace metals.

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(148) Standard Method of Test for Proximate Analysis of Coal and Coke, Designation D 3172-73. In: 1973 Annual Book of ASTM Standards, Part 19: Gaseous Fuels; Coal and Coke. American Society for Testing and Materials, Philadelphia, Pennsylvania, 1973. p. 434.

(149) Standard Method of Test for Forms of Sulfur in Coal, Designation D 2492-68. In: 1973 Annual Book of ASTM Standards, Part 19: Gaseous Fuels; Coal and Coke. American Society for Testing and Materials, Philadelphia, Pennsylvania, 1973. pp. 380-384.

Trace Organic Analysis

Trace organic analysis was conducted on pentane extractions of the water and leachate samples and on the organic components from the SASS collection, which were contained in the pentane extractions of the cyclone and filter catch, the pentane extract of the XAD-2 resin trap, and in the solid residue from the probe washes. Portions of the pentane extracts were analyzed for low-molecular-weight (C_7 to C_{12}) organic compounds with a flame ionization gas chromatograph using a 1.5% OV-101 on Gas Chrom Q 100/120 mesh (3 mm x 1.8 m) stainless steel column. Following chromatography, the liquids were evaporated to $\sim 2.5 \times 10^{-5}$ m³ ($\sim$25 ml) using rotary evaporation. The residue from the probe wash was dissolved in 2.5×10^{-5} m³ (25 ml) of pentane.

Following volume reduction, the samples were separated into eight fractions, using the solvent systems shown in Figure C-6, on a silica gel column. Each fraction was then reduced in volume using a Kuderna-Danish evaporator and transferred to a tare-weighted, micro-weighing pan; the remaining solvent was evaporated in air. Each dried fraction was weighed and then redissolved in a minimum quantity of methylene chloride.

The second, third and fourth fractions (containing the POM and PCB components) were combined and transferred to a Viton-septum sealed vial which was covered with aluminum foil and refrigerated until required for analysis. Just prior to analysis, the sample underwent one more volume reduction via the Kuderna-Danish method. The final volume was approximately 5×10^{-7} m³ (500 μl). This volume size has been found to be optimum for detecting the POM peaks without them being obscured by the contamination peaks.

POM Analysis Procedure--

The method used for POM analysis employs a peak-area quantitation technique with computer reconstructed chromatograms from the (HP 5982-A) gas chromatograph - mass spectrograph (GC-MS). All data were collected in the electron impact (EI) mode because of the abundance of available EI-mass spectra.

The gas chromatographic separation was achieved using a 1.8-m Dexsil 400 glass column with temperature programming from 160°C for 2 min, rising to 280°C at 8°C/min, and becoming isothermal at 280°C. Helium, at a flow rate of 0.5×10^{-9} m/s (30 μl/min), was used as carrier gas.

The mass spectrometer, operating in the electron impact mode, was programmed to scan the 75-350 AMU range as the POM components eluted from the gas chromatograph. The data system reconstructed the chromatogram using the total ion mode. POM's were located by their molecular mass ions which are displayed using the selected ion mode (SIM). Their identity was confirmed by examination of their mass spectra and retention times.

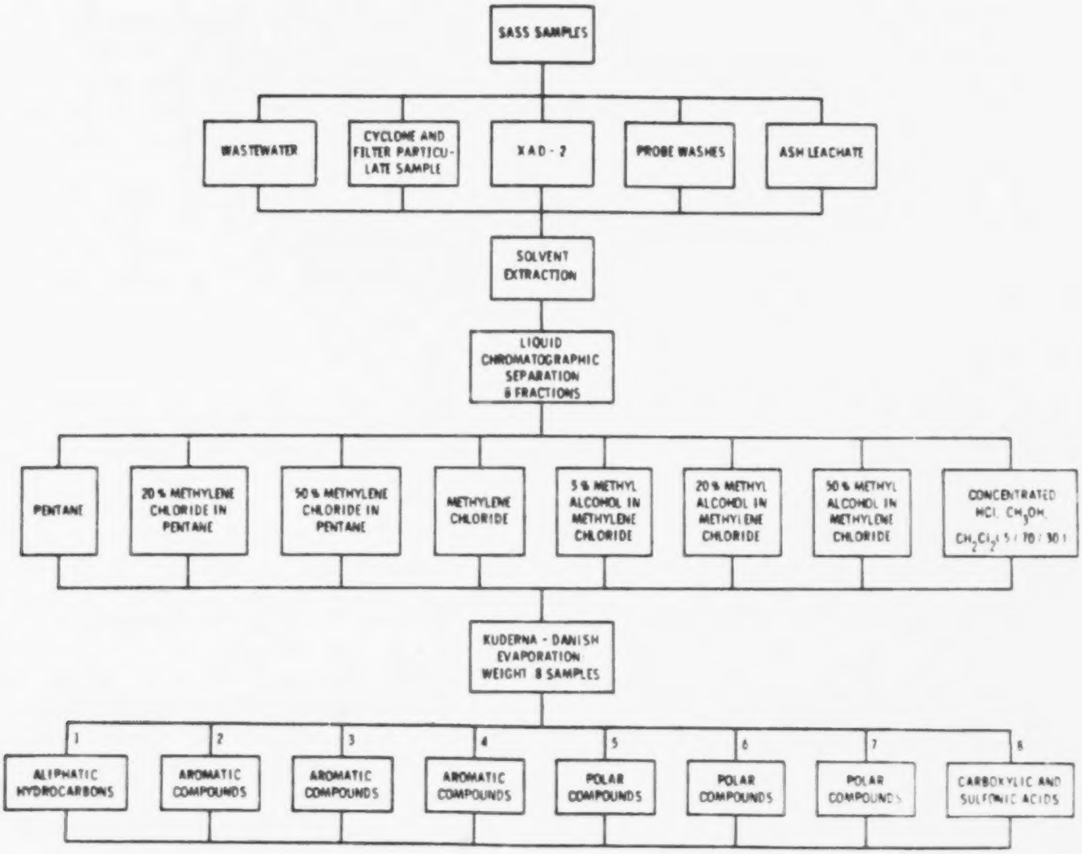
SASS SAMPLES
WASTEWATER
CYCLONE AND FILTER PARTICULATE SAMPLE
XAD - 2
PROBE WASHES
ASH LEACHATE
SOLVENT EXTRACTION
LIQUID CHROMATOGRAPHIC SEPARATION 8 FRACTIONS
PENTANE
20 % METHYLENE CHLORIDE IN PENTANE
50 % METHYLENE CHLORIDE IN PENTANE
METHYLENE CHLORIDE
5 % METHYL ALCOHOL IN METHYLENE CHLORIDE
20 % METHYL ALCOHOL IN METHYLENE CHLORIDE
50 % METHYL ALCOHOL IN METHYLENE CHLORIDE
CONCENTRATED HCl, CH_3OH, CH_2Cl_2 (5 / 70 / 30)
KUDERNA - DANISH EVAPORATION WEIGHT 8 SAMPLES
1
ALIPHATIC HYDROCARBONS
2
AROMATIC COMPOUNDS
3
AROMATIC COMPOUNDS
4
AROMATIC COMPOUNDS
5
POLAR COMPOUNDS
6
POLAR COMPOUNDS
7
POLAR COMPOUNDS
8
CARBOXYLIC AND SULFONIC ACIDS

Figure C-6. Analysis flow diagram.

Calibration curves were prepared for each POM of interest using varying concentrations of the POM standards in methylene chloride, plotting mass ion peak area vs. concentration, and determining response factors. POM peaks in samples were compared with standard curves that have been obtained under the same conditions, attenuation, injection volume (2×10^{-9} m^3 or 2 µl), and tuning condition. Calibrations were made on the same day that the samples were analyzed.

PCB Analysis Procedure--

The GC-MS technique was used for the analysis of PCB compounds. Concentrated solutions from the second, third and fourth fractions from the silica gel separations were examined. Samples were injected into the GC and separated on a 3% Dexsil 400 column operated isothermally at 250°C for SIM or 280°C SMS modes. Mass spectra were obtained in the electron impact mode because the fragmentations of a number of isomeric mono-, di-, tri-, tetra-, bena-, octa- and decachloro-biphenyl has been studied in detail using this procedure. Quantification of the data was performed using standards of the various chlorinated biphenyls in methylene chloride.

Trace Elmenent Analyses

The Jarrell-Ash Plasma Atomcomp (ICAP) and atomic absorption methods were used for trace element analysis of the collected samples.

Jarrell-Ash Plasma Atomcomp Analysis--

The Jarrell-Ash Plasma Atomcomp technique was used at the Physical Science Center of Monsanto Company in St. Louis for the analysis of aluminum, antimony, barium, boron, cadmium, calcium, chromium, cobalt, copper, iron, lead, magnesium, manganese, molybdenum, nickel, phosphorus, silicon, silver, sodium, tin, strontium, titanium, vanadium and zinc. The Atomcomp employs an inductively coupled argon plasma (ICAP) as an excitation source to produce atomic emission which is relatively free of interferences.

Atomic Absorption Analysis--

Atomic absorption was employed to analyze for mercury, arsenic, selenium, antimony, beryllium and zirconium. Mercury was analyzed using the cold vapor technique in which all of the mercury is reduced to the metallic state with $SnCl_2$ and then swept into the Quartz Cuvette for AA analysis (150). Arsenic, selenium and antimony were analyzed via the hydride generation technique developed and refined by Fernandez (151) and more recently by Brodie (152). An aqueous solution was first reacted with a reducing agent (e.g., potassium iodide), then the corresponding gaseous hydride was generated with sodium borohydride which was immediately swept into a nitrogen-hydrogen entrained-air flame for analysis.

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(150) Parker, C. R. Water Analysis by Atomic Absorption. Varian Techtron Pty. Ltd., Springvale, Victoria, Australia, Reprint 1976. 78 pp.

Beryllium and zirconium were analyzed using conventional air-acetylene flame atomic absorption methods.

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(151) Fernandez, F. G. Atomic Absorption Determination of Gaseous Hydrides Utilizing Sodium Borohydride Reduction. Atomic Absorption Newsletter, 12(4):93-97, 1973.

(152) Brodie, K. G. Determining Arsenic and Selenium by AAS. American Laboratory, 9(3):73-79, 1977.

APPENDIX D

DERIVATION OF SOURCE SEVERITY EQUATIONS

SUMMARY OF SEVERITY EQUATIONS FOR AIR POLLUTANTS

The severity (S) of pollutants may be calculated using the mass emission rate (Q), the height of the emissions (H), and the threshold limit value (TLV) (for noncriteria pollutants) (64). The equations summarized in Table D-1 are developed in detail in this appendix.

TABLE D-1. POLLUTANT SEVERITY EQUATIONS FOR ELEVATED POINT SOURCES

Pollutants	Severity equation
Particulate	$S_P = \frac{70\ Q}{H^2}$
SO_x	$S_{SO_x} = \frac{50\ Q}{H^2}$
NO_x	$S_{NO_x} = \frac{315\ Q}{H^{2.1}}$
Hydrocarbon	$S_{HC} = \frac{162\ Q}{H^2}$
CO	$S_{CO} = \frac{0.78\ Q}{H^2}$
Other	$S_A = \frac{5.5\ Q}{TLV \bullet H^2}$

DERIVATION OF χ_{max} FOR USE WITH U.S. AVERAGE CONDITIONS

The most widely accepted formula for predicting downwind ground level concentrations from a point source is (60).

$$\chi = \frac{Q}{\pi \sigma_y \sigma_z u} \exp\left[-\frac{1}{2}\left(\frac{y}{\sigma_y}\right)^2\right] \exp\left[-\frac{1}{2}\left(\frac{H}{\sigma_z}\right)^2\right] \qquad \text{(D-1)}$$

where χ = downwind ground level concentration at reference coordinate x and y with emission height of H, g/m³
Q = mass emission rate, g/s
π = 3.14
σ_y = standard deviation of horizontal dispersion, m
σ_z = standard deviation of vertical dispersion, m
u = wind speed, m/s
y = horizontal distance from centerline of dispersion, m
H = height of emission release, m
x = downwind dispersion distance from source of emission release, m

We assume that χ_{max} occurs when x is much greater than 0 and y equals 0. For a given stability class, standard deviations of horizontal and vertical dispersion have often been expressed as a function of downwind distance by power law relationships as follows (153):

$$\sigma_y = ax^b \tag{D-2}$$

$$\sigma_z = cx^d + f \tag{D-3}$$

Values for a, b, c, d, and f are given in Tables D-2 (154) and D-3. Substituting these general equations into Equation D-1 yields

$$\chi = \frac{Q}{ac\pi ux^{b+d} + a\pi ufx^b} \exp\left[- \frac{H^2}{2(cx^d + f)^2}\right] \tag{D-4}$$

Assuming that χ_{max} occurs at x less than 100 m and the stability class is C, then f equals 0 and Equation D-4 becomes

$$\chi = \frac{Q}{ac\pi ux^{b+d}} \exp\left[\frac{-H^2}{2c^2x^{2d}}\right] \tag{D-5}$$

For convenience, let

$$A_R = \frac{Q}{ac\pi u} \text{ and } B_R = \frac{-H^2}{2c^2}$$

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(153) Martin, D. O., and J. A. Tikvart. A General Atmospheric Diffusion Model for Estimating the Effects on Air Quality of One or More Sources. Presented at the 61st Annual Meeting of the Air Pollution Control Association, St. Paul, Minnesota, June 23-27, 1968. 18 pp.

(154) Eimutis, E. C., and M. G. Konicek. Derivations of Continuous Functions for the Lateral and Vertical Atmospheric Dispersion Coefficients. Atmospheric Environment, 3(6): 688-689, 1969.

TABLE D-2. VALUES OF a FOR THE COMPUTATION OF σ_y[a] (155)

Stability class	a
A	0.3658
B	0.2751
C	0.2089
D	0.1471
E	0.1046
F	0.0722

[a] For Equation D-2: $\sigma_y = ax^b$

where x = downwind distance
b = 0.9031 (from Reference 155)

TABLE D-3. VALUES OF THE CONSTANTS USED TO ESTIMATE VERTICAL DISPERSION[a] (153)

Usable range, m	Stability class	Coefficient		
		c_1	d_1	f_1
>1,000	A	0.00024	2.094	-9.6
	B	0.055	1.098	2.0
	C	0.113	0.911	0.0
	D	1.26	0.516	-13
	E	6.73	0.305	-34
	F	18.05	0.18	-48.6
		c_2	d_2	f_2
100 to 1,000	A	0.0015	1.941	9.27
	B	0.028	1.149	3.3
	C	0.113	0.911	0.0
	D	0.222	0.725	-1.7
	E	0.211	0.678	-1.3
	F	0.086	0.74	-0.35
		c_3	d_3	f_3
<100	A	0.192	0.936	0
	B	0.156	0.922	0
	C	0.116	0.905	0
	D	0.079	0.881	0
	E	0.063	0.871	0
	F	0.053	0.814	0

[a] For Equation D-3: $\sigma_z = cx^d + f$

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(155) Tadmor, J., and Y. Gur. Analytical Expressions for the Vertical and Lateral Dispersion Coefficients in Atmospheric Diffusion. Atmospheric Environment, 3(6):688-689, 1969.

so that Equation D-5 reduces to

$$\chi = A_R x^{-(b+d)} \exp\left[\frac{B_R}{x^{2d}}\right] \qquad \text{(D-6)}$$

Taking the first derivative of Equation D-6

$$\frac{d\chi}{dx} = A_R \left\{ x^{-b-d} \left(\exp\left[B_R x^{-2d}\right]\right)\left(-2dB_R x^{-2d-1}\right) + \exp\left[B_R x^{-2d}\right]\left(-b-d\right) x^{-b-d-1} \right\} \qquad \text{(D-7)}$$

and setting this equal to zero (to determine the roots which give the minimum and maximum conditions of χ with respect to x) yields

$$\frac{d\chi}{dx} = 0 = A_R x^{-b-d-1} \left[\exp\left(B_R x^{-2d}\right)\right]\left(-2dB_R x^{-2d} - b - d\right) \qquad \text{(D-8)}$$

Since we define that $x \neq 0$ or ∞ at χ_{max}, the following expression must be equal to 0.

$$-2dB_R x^{-2d} - d - b = 0 \qquad \text{(D-9)}$$

or

$$(b+d)x^{2d} = -2dB_R \qquad \text{(D-10)}$$

or

$$x^{2d} = \frac{-2dB_R}{b+d} = \frac{2dH^2}{2c^2(b+d)} \qquad \text{(D-11)}$$

or

$$x^{2d} = \frac{dH^2}{c^2(b+d)} \qquad \text{(D-12)}$$

Hence

$$x = \left(\frac{dH^2}{c^2(b+d)}\right)^{1/2d} \text{ at } \chi_{max} \qquad \text{(D-13)}$$

Thus Equations D-2 and D-3 (at f = 0) become

$$\sigma_y = a\left(\frac{dH^2}{c^2(d+b)}\right)^{b/2d} \qquad \text{(D-14)}$$

$$\sigma_z = c\left[\frac{dH^2}{c^2(b+d)}\right]^{d/2d} = \left(\frac{dH^2}{b+d}\right)^{1/2} \qquad \text{(D-15)}$$

The maximum will be determined for U.S. average conditions of stability. According to Gifford (156), this is when σ_y equals σ_z.

Since b equals 0.9031, and upon inspection of Table D-2 under U.S. average conditions, σ_y equals σ_z, it can be seen that 0.881 is less than or equal to d which is less than or equal to 0.905 (class C stability[a]). Thus, it can be assumed that b is nearly equal to d or in Equations D-14 and D-15 or

$$\sigma_z = \frac{H}{\sqrt{2}} \qquad \text{(D-16)}$$

and

$$\sigma_y = \frac{a}{c}\,\frac{H}{\sqrt{2}} \qquad \text{(D-17)}$$

Under U.S. average conditions, σ_y equals σ_z and a approximates c if b approximates d and f equals 0 (between class C and D, but closer to belonging in class C).

Then

$$\sigma_y = \frac{H}{\sqrt{2}} \qquad \text{(D-18)}$$

Substituting for σ_y from Equation D-18 and for σ_z from Equation D-16 into Equation D-1 and letting y equal 0

$$\chi_{max} = \frac{2\ Q}{\pi u H^2}\,\exp\left[-\,\frac{1}{2}\left(\frac{H\sqrt{2}}{H}\right)^2\right] \qquad \text{(D-19)}$$

or

$$\chi_{max} = \frac{2\ Q}{\pi e u H^2} \qquad \text{(D-20)}$$

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[a] The values given in Table D-3 are mean values for stability class. Class C stability describes these coefficients and exponents, only within about a factor of two.

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(156) Gifford, F. A., Jr. An Outline of Theories of Diffusion in the Lower Layers of the Atmosphere. In: Meteorology and Atomic Energy 1968, Chapter 3, D. A. Slade, ed. Publication No. TID-24190, U.S. Atomic Energy Commission Technical Information Center, Oak Ridge, Tennessee, July 1968. p. 113.

For U.S. average conditions, u equals 4.47 m/s so that Equation D-20 reduces to

$$\chi_{max} = \frac{0.0524\ Q}{H^2} \qquad \text{(D-21)}$$

DEVELOPMENT OF SOURCE SEVERITY EQUATIONS

Source severity, S, has been defined as follows:

$$S = \frac{\overline{\chi}_{max}}{F} \qquad \text{(D-22)}$$

where $\overline{\chi}_{max}$ = time-averaged maximum ground level concentration
F = hazard factor; for criteria pollutants, F = AAQS; for noncriteria pollutants, F = TLV • 8/24 • 1/100.

Noncriteria Emissions

The value of $\overline{\chi}_{max}$ may be derived from χ_{max}, and undefined "short-term" concentration. An approximation for longer term concentration may be made as follows:

For a 24-hr time period,

$$\overline{\chi}_{max} = \chi_{max}\left(\frac{t_o}{t}\right)^{0.17} \qquad \text{(D-23)}$$

where t_o = instantaneous (i.e., 3-min) averaging time
t = averaging time period used (i.e., 24 hr or 1,440 min)

Hence

$$\overline{\chi}_{max} = \chi_{max}\left(\frac{3\ \text{min}}{1,440\ \text{min}}\right)^{0.17} \qquad \text{(D-24)}$$

$$\overline{\chi}_{max} = \chi_{max}\ (0.35) \qquad \text{(D-25)}$$

Since the hazard factor is defined and derived from TLV values as follows:

$$F = (\text{TLV})\left(\frac{8}{24}\right)\left(\frac{1}{100}\right) \qquad \text{(D-26)}$$

$$F = (3.33 \times 10^{-3})\ \text{TLV} \qquad \text{(D-27)}$$

then the severity factor, S_a, is defined as

$$S_a = \frac{\overline{\chi}_{max}}{F} = \frac{0.35\ \chi_{max}}{(3.33 \times 10^{-3})\ \text{TLV}} \qquad \text{(D-28)}$$

$$S_a = \frac{105\ \chi_{max}}{TLV} \qquad \text{(D-29)}$$

If a weekly averaging period is used, then

$$\overline{\chi}_{max} = \chi_{max}\left(\frac{3}{10{,}080}\right)^{0.17} \qquad \text{(D-30)}$$

or

$$\overline{\chi}_{max} = 0.25\ \chi_{max} \qquad \text{(D-31)}$$

and

$$F = (TLV)\left(\frac{40}{168}\right)\left(\frac{1}{100}\right) \qquad \text{(D-32)}$$

$$F = (2.38 \times 10^{-3})TLV \qquad \text{(D-33)}$$

and the severity factor, S_a, is

$$S_a = \frac{\overline{\chi}_{max}}{F} = \frac{0.25\ \chi_{max}}{(2.38 \times 10^{-3})TLV} \qquad \text{(D-34)}$$

or

$$S_a = \frac{105\ \chi_{max}}{TLV} \qquad \text{(D-35)}$$

which is entirely consistent, since the TLV is being corrected for a different exposure period.

Therefore, the severity can be derived from χ_{max} directly without regard to averaging time for noncriteria emissions. Thus, combining Equations D-35 and D-21, for elevated sources, gives

$$S_a = \frac{5.5\ Q}{TLV \bullet H^2} \qquad \text{(D-36)}$$

Criteria Emissions

For the criteria pollutants, established standards may be used as F values in Equation D-22. These are given in Table D-4 (63). However, Equation D-23 must be used to give the appropriate averaging period. These equations are developed for elevated sources using Equation D-21.

TABLE D-4. SUMMARY OF NATIONAL AMBIENT AIR QUALITY STANDARDS (63)

Pollutant	Averaging time	Primary standards, $\mu g/m^3$	Secondary standards, $\mu g/m^3$
Particulate matter	Annual (geometric mean)	75	60[a]
	24-hr[b]	260	160
SO_x	Annual (arithmetic mean)	80	60
	24-hr[b]	365	260[c]
	3-hr[b]	-[d]	1,300
CO	8-hr[b]	10,000	10,000
	1-hr[b]	40,000	40,000
Nitrogen dioxide	Annual (arithmetic mean)	100	100
Photochemical oxidants	1-hr[b]	160	160
Hydrocarbons (nonmethane)	3-hr (6 a.m. to 9 a.m.)	160[e]	160

[a] The secondary annual standard (60 $\mu g/m^3$) is a guide for assessing implementation plans to achieve the 24-hr secondary standard.

[b] Not to be exceeded more than once per year.

[c] The secondary annual standard (260 $\mu g/m^3$) is a guide for assessing implementation plans to achieve the annual standard.

[d] No standard exists.

[e] There is no primary ambient air quality standard for hydrocarbons. The value of 160 $\mu g/m^3$ used for hydrocarbons in this report is an EPA-recommended guideline for meeting the primary ambient air quality standard for oxidants.

Carbon Monoxide Severity--
The primary standard for CO is reported for a 1-hr averaging time. Therefore

$$t = 60 \text{ min}$$

$$t_o = 3 \text{ min}$$

$$\bar{\chi}_{max} = \chi_{max} \left(\frac{3}{60}\right)^{0.17} \quad \text{(D-37)}$$

$$= \frac{2\ Q}{\pi e u H^2} \left(\frac{3}{60}\right)^{0.17} \quad \text{(D-38)}$$

$$= \frac{2\ Q}{(3.14)(2.72)(4.5)H^2}\ 0.6 \quad \text{(D-39)}$$

$$\bar{\chi}_{max} = \frac{0.052\ Q}{H^2}\ 0.6 \quad \text{(D-40)}$$

$$\bar{\chi}_{max} = \frac{(3.12 \times 10^{-2})Q}{H^2} \quad \text{(D-41)}$$

$$\text{Severity, } S = \frac{\overline{\chi}_{max}}{F} \quad \text{(D-42)}$$

Setting F equal to the primary AAQS for CO or 0.04 g/m³ yields

$$S = \frac{\overline{\chi}_{max}}{F} = \frac{(3.12 \times 10^{-2})Q}{0.04\ H^2} \quad \text{(D-43)}$$

or

$$S_{CO} = \frac{0.78\ Q}{H^2} \quad \text{(D-44)}$$

Hydrocarbon Severity--
The primary standard for nonmethane hydrocarbons is reported for a 3-hr averaging time.

$$t = 180 \text{ min}$$

$$t_0 = 3 \text{ min}$$

$$\overline{\chi}_{max} = \chi_{max} \left(\frac{3}{180}\right)^{0.17} \quad \text{(D-45)}$$

$$= 0.5\ \chi_{max} \quad \text{(D-46)}$$

$$= \frac{(0.5)(0.052)Q}{H^2} \quad \text{(D-47)}$$

$$\overline{\chi}_{max} = \frac{0.026\ Q}{H^2} \quad \text{(D-48)}$$

For nonmethane hydrocarbons, the concentraiton of 1.6×10^{-4} g/m³ has been issued as a guideline for achieving oxidant standards. Therefore,

$$S = \frac{\overline{\chi}_{max}}{F} = \frac{0.026\ Q}{1.6 \times 10^{-4}\ H^2} \quad \text{(D-49)}$$

or

$$S_{HC} = \frac{162.5\ Q}{H^2} \quad \text{(D-50)}$$

Particulate Severity--
The primary standard for particulate is reported for a 24-hr averaging time.

$$\overline{\chi}_{max} = \chi_{max} \left(\frac{3}{1,440}\right)^{0.17} \tag{D-51}$$

$$= \frac{(0.35)(0.052)Q}{H^2} \tag{D-52}$$

$$\overline{\chi}_{max} = \frac{0.0182\ Q}{H^2} \tag{D-53}$$

For particulates, F equals the primary AAQS or 2.6×10^{-4} g/m³, and

$$S = \frac{\overline{\chi}_{max}}{F} = \frac{0.0182\ Q}{(2.6 \times 10^{-4})H^2} \tag{D-54}$$

$$S_P = \frac{70\ Q}{H^2} \tag{D-55}$$

SO_x Severity--
The primary standard for SO_x is reported for a 24-hr averaging time. Using t = 1,440 minutes and proceeding as before:

$$\overline{\chi}_{max} = \frac{0.0182\ Q}{H^2} \tag{D-56}$$

The primary AAQS for SO_x is 3.65×10^{-4} g/m³. Therefore,

$$S = \frac{\overline{\chi}_{max}}{F} = \frac{0.0182\ Q}{(3.65 \times 10^{-4})H^2} \tag{D-57}$$

or

$$S_{SO_x} = \frac{50\ Q}{H^2} \tag{D-58}$$

NO_x Severity--
Since NO_x has a primary standard with a 1-yr averaging time, the χ_{max} correction equation cannot be used. As an alternative, the following equation is used:

$$\overline{\chi} = \frac{2.03\ Q}{\sigma_z ux} \exp\left[-\frac{1}{2}\left(\frac{H}{\sigma_z}\right)^2\right] \tag{D-59}$$

A difficulty arises, however, because a distance x, from emission point to receptor, is included; hence, the following rationale is used:

$$\chi_{max} = \frac{2\ Q}{\pi e u H^2} \tag{D-20}$$

Equation D-20, shown earlier is valid for neutral conditions or when σ_z approximately equals σ_y.

This maximum occurs when

$$H = \sqrt{2}\sigma_z \tag{D-60}$$

and since, under these conditions,

$$\sigma_z = ax^b \tag{D-61}$$

then the distance, x_{max}, where the maximum concentration occurs is

$$x_{max} = \left(\frac{H}{\sqrt{2}a}\right)^{1/b} \tag{D-62}$$

For class C conditions, a = 0.113 and b = 0.911. Substituting these values into Equation D-62 yields:

$$x_{max} = \frac{H^{1.098}}{0.16} = 7.5\ H^{1.098} \tag{D-63}$$

Since

$$\sigma_z = 0.113\ x_{max}{}^{0.911} \tag{D-64}$$

and

$$\dot{u} = 4.5\ \text{m/s}$$

and letting $x = x_{max}$, Equation D-59 becomes

$$\overline{\chi}_{max} = \frac{4\ Q}{x_{max}{}^{1.911}} \exp\left[-\frac{1}{2}\left(\frac{H}{\sigma_z}\right)^2\right] \tag{D-65}$$

where

$$\frac{4\ Q}{x_{max}{}^{1.911}} = \frac{4\ Q}{(7.5\ H^{1.098})^{1.911}} \tag{D-66}$$

Therefore,

$$\overline{\chi}_{max} = \frac{0.085\ Q}{H^{2.1}} \exp\left[-\frac{1}{2}\left(\frac{H}{\sigma_z}\right)^2\right] \tag{D-67}$$

As noted above,

$$\sigma_z = 0.113\ x^{0.911} \quad \text{(D-64)}$$

Substituting for x yields

$$\sigma_z = 0.113(7.5\ H^{1.1})^{0.911} \quad \text{(D-68)}$$

or

$$\sigma_z = 0.71\ H \quad \text{(D-69)}$$

Therefore,

$$\overline{\chi}_{max} = \frac{0.085\ Q}{H^{2.1}} \exp\left[-\frac{1}{2}\left(\frac{H}{0.71\ H}\right)^2\right] \quad \text{(D-70)}$$

$$= \frac{0.085\ Q}{H^{2.1}}\ (0.371) \quad \text{(D-71)}$$

$$\overline{\chi}_{max} = \frac{3.15 \times 10^{-2}\ Q}{H^{2.1}} \quad \text{(D-72)}$$

Since the AAQS for NO_x is 1.0×10^{-4} g/m³, the NO_x severity equation is

$$S_{NO_x} = \frac{(3.15 \times 10^{-2})Q}{1 \times 10^{-4}\ H^{2.1}} \quad \text{(D-73)}$$

$$S_{NO_x} = \frac{315\ Q}{H^{2.1}} \quad \text{(D-74)}$$

AFFECTED POPULATION CALCULATION

Another form of the plume dispersion equation is needed to calculate the affected population since the population is assumed to be distributed uniformly around the source. If the wind directions are taken to 16 points and it is assumed that the wind directions within each sector are distributed randomly over a period of a month or a season, it can be assumed that the effluent is uniformly distributed in the horizontal within the sector. The appropriate equation for average concentration, $\overline{\chi}$, in grams per cubic meter is then (for 100 m ≤ x ≤ 1,000 m and stability class C) (65):

$$\overline{\chi} = \frac{2.03\ Q}{\sigma_z u x} \exp\left[-\frac{1}{2}\left(\frac{H}{\sigma_z}\right)^2\right] \quad \text{(D-75)}$$

To find the distances at which $\overline{\chi}$/AAQS equals 1.0, roots are determined for the following equation:

$$\frac{2.03\ Q}{(\text{AAQS})\sigma_z u x} \exp\left[-\frac{1}{2}\left(\frac{H}{\sigma_z}\right)^2\right] = 1.0 \qquad \text{(D-76)}$$

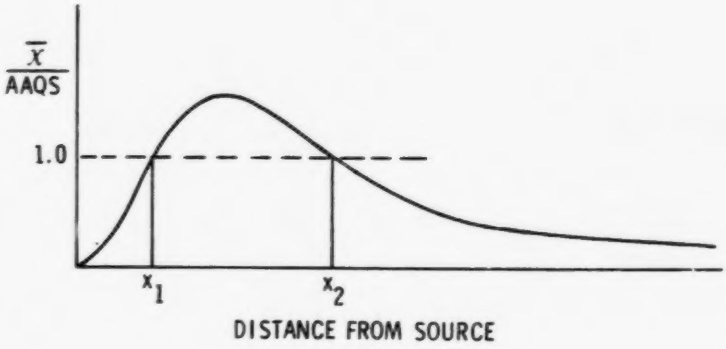
keeping in mind that

$$\sigma_z = ax^b + c$$

where a, b, and c are functions of atmospheric stability and are assumed to be selected for stability Class C.

Since Equation D-76 is a transcendental equation, the roots are found by an iterative technique using the computer.

For a specified emission from a typical source, $\overline{\chi}$/AAQS as a function of distance might look as follows:



The affected population is contained in the area

$$A = \pi(x_2^2 - x_1^2) \qquad \text{(D-77)}$$

If the affected population density is D_p, the total affected population, P', is

$$P' = D_pA \text{ (persons)} \qquad \text{(D-78)}$$

EFFLUENT SOURCE SEVERITY

Various mathematical models can be conceived to describe the impact of a discharge on a receiving body. Such systems are complex and not fully understood. Pertinent factors deserving consideration include the number of discharge streams; the flow rate and composition (chemical and physical characteristics) of each discharge stream; the hazardous nature of the discharge; the volume, flow rate, and water quality of the receiving body; and the ability of the receiving body to detoxify the discharge. In an effluent stream containing many materials, each species may have a different environmental impact; in addition, synergestic interactions may occur.

For this assessment study, it was decided to adopt a simplified approach in which the resultant concentration of a specific pollutant is compared to an associated hazard factor. Three simple models can be considered depending on the degree of mixing with the receiving body. In the first case, the source severity (S_e) was defined for each discharge as follows:

$$S_{BD} = \frac{C_D}{F_e} \qquad \text{(D-79)}$$

where S_{BD} = severity due to a pollutant in a discharge stream before dilution
C_D = concentration of pollutant in effluent, g/m³
F_e = hazard factor, equal to a potentially hazardous concentration, g/m³

Equation D-79 describes what may be termed the end-of-pipe severity for the discharge stream. Once an effluent enters a receiving body, it is diluted by the receiving body water and the severity decreases. The severity within a mixing zone is defined as follows:

$$S_{MZ} = \left(\frac{V_D}{V_D + F_{MZ} \bullet vr}\right)\left(\frac{C_D}{F_e}\right) \qquad \text{(D-80)}$$

where S_{MZ} = severity due to a pollutant in a mixing zone
V_D = effluent discharge rate, m³/s
vr = river flow rate, m³/s
F_{MZ} = fraction of river flow in mixing zone; i.e., 1/3, 1/4

The severity after the mixing zone, S_{AMZ}, is given by:

$$S_{AMZ} = \left(\frac{V_D}{V_D + vr}\right)\left(\frac{C_D}{F_e}\right) \qquad \text{(D-81)}$$

where S_{AMZ} = severity due to a pollutant after a mixing zone

These relationships are shown in Figure D-1.

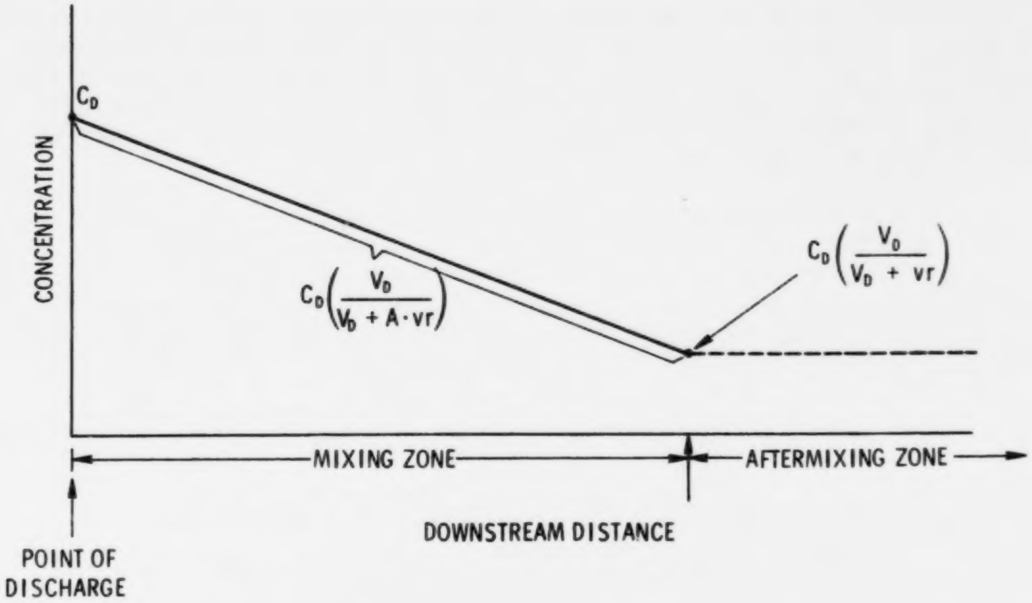


Figure D-1. Change of concentration with distance.

If vr is much greater than V_D, then

$$S_{AMZ} = \left(\frac{V_D}{vr}\right)\left(\frac{C_D}{F_e}\right) \tag{D-82}$$

Equation D-82 defines the effluent source severity, S_e, used in this report with one exception. The term vr was replaced with the minimum river flow rate, V_R, to maximize the severity term. It is important to note that this effluent source severity is not an aggregate parameter; instead, it refers to one pollutant within one discharge stream. A more detailed treatment of the effluent source severity is available in the literature (108).

GLOSSARY

air preheater: Device that preheats combustion air using waste heat recovered from flue gas.

affected population: Number of persons around an average source who are exposed to a source severity greater than 0.05 or 1.0, as specified.

ash sluicing: Transport of ash as aqueous slurry.

beneficiation: Physical cleaning of coal to remove mineral matter.

bituminous: Coal covering a wide range of properties, but in general having a fixed carbon content less than 80% and volatile matter exceeding 20%.

blowdown: Boiler water or cooling water wasted from a closed circulatory system to limit the buildup of dissolved solids.

boiler efficiency: Ratio of boiler heat output, measured as the heat content of the steam produced, to boiler heat input, measured as the heat content of the coal feed.

boiler tubes: Cylindrical tubes, located in convection passes and on furnace side walls, in which heat from the furnace is transferred to the boiler water.

bottom hopper: Container fitted to bottom of furnace to collect ash that falls to furnace floor.

capacity: Maximum heat or maximum steam output for which boiler is designed.

clarification: Removal of suspended solids from feedwater by quiesent settling.

combustion zone: Layer surrounding each coal particle where the mixing of combustibles and air forms a combustible mixture, and a diffusion flame is established.

criteria pollutants: Pollutants for which ambient air quality standards have been established.

cyclone: Device that uses centrifugal forces to separate particulate matter from gas.

diffusion flame: Flame established around a solid where combustible material must diffuse into the oxidant in order for combustion to take place.

direct feed: Fuel supply system in which coal is fed directly from pulverizers to burners.

dispersed concentration: Concentration of water pollutant in receiving body after mixing.

dry bottom furnace: Furnace in which operating temperature is kept below ash fusion temperature so that bottom ash can be removed as dry powder.

economizer: Device that preheats boiler feedwater using waste heat recovered from flue gas.

effluent factor: Quantity of effluent species discharged per quantity of mass burned.

emission factor: Quantity of emission species emitted per quantity of mass burned.

enrichment: Concentration of certain elements in fly ash due to their partitioning behavior at furnace temperatures.

evaporator: Device used to purify boiler feedwater by thermal vaporization.

excess air: Air added to furnace in excess of that required for stoichiometric combustion.

exchange capacity: Maximum quantity of dissolved ions that can be adsorbed by an ion exchanger without breakthrough occurring.

external combustion: Combustion which takes place outside of the working fluid of a heat-to-work conversion device; all boilers require external combustion.

firing capacity: Maximum amount of heat input for which a furnace is designed.

fixation: Solidification of waste sludges by addition of chemicals.

flue gas dew point: Temperature at which vapors in flue gas begin to condense.

fly ash: Portion of noncombustible residue from fuel, carried out of boiler by flue gas.

hardness: Concentration of scale-forming ions in water.

hazard factor: Lowest concentration of pollutant which has been shown to be detrimental to health or environment.

horizontally fired furnace: Furnace in which burners are located in side walls.

indirect feed: Fuel supply system in which coal leaving pulverizers is fed to a storage hopper which supplies the burners.

ion exchange: Reversible interchange of ions between a liquid and a solid with no radical change in the structure of the solid; used for purification of boiler feedwater.

output capacity: Maximum quantity of steam at given pressure which a boiler is designed to generate.

overfire air: Combustion air admitted to furnace just above flame.

partitioning: Separation of a substance between two phases.

pulverized: Finely divided; at least 80% of pulverized coal will pass through a 200-mesh sieve.

pulverizer: Device that crushes coal to fineness necessary for combustion in a pulverized, coal-fired furnace.

pyrolysis: Chemical decomposition by application of heat in oxygen-deficient atmosphere.

reheater: Heat exchange device for adding superheat to steam which has been partially expanded in a turbine.

slag: Molten form of noncombustible fuel residue remaining in furnace after combustion.

softening: Removal of hardness-causing ions from water using chemical precipitation or ion exchange.

source severity: Indication of the hazard potential of an emission source.

staged combustion: Fuel-rich combustion achieved by diverting portion of combustion air to port near tip of flame.

state emission burden: Ratio of annual emissions from a specific source in any state to the total state emissions from all stationary sources.

superheater: Device for heating steam to a temperature above that corresponding to saturation at a specific pressure.

tangentially fired furnace: Furnace in which burners are located in corners and directed toward the edges of an imaginary circle in the center of the furnace, thus imparting a swirling motion to the flames.

threshold limit value (TLV): Airborne concentrations of substances; represents conditions under which it is believed that nearly all workers may be repeatedly exposed day after day without adverse effect.

utilization factor: Ratio of actual output of boiler, as required by demand, to related output.

vertically fired furnace: Furnace in which burner is located in furnace ceiling and directed downward.

water quality criteria: Concentrations of selected pollutants at which damage to selected biological species has been shown to occur.

water walls: Furnace walls composed of boiler tubes.

wet bottom furnace: Furnace in which operating temperature is above ash fusion temperature so that portion of ash remaining in furnace is in molten form.

CONVERSION FACTORS AND METRIC PREFIXES (157)

CONVERSION FACTORS

To convert from	To	Multiply by
Degree Celsius (°C)	Degree Fahrenheit (°F)	$t_{°F} = 1.8\ t_{°C} + 32$
Gram/kilogram (g/kg)	Pound/ton	2.000
Joule (J)	Btu	9.478×10^{-4}
Kilogram (kg)	Pound-mass (avoirdupois)	2.205
Meter (m)	Foot	3.281
Meter (m)	Inch	3.937×10^{1}
Meter² (m²)	Mile²	3.861×10^{-7}
Meter³ (m³)	Foot³	3.531×10^{1}
Metric ton	Ton (short, 2,000 pound mass)	1.102
Pascal (Pa)	Inch of water (60°F)	4.019×10^{-3}
Second (s)	Minute	1.667×10^{-2}

PREFIXES

Prefix	Symbol	Multiplication factor	Example
Exa	E	10^{18}	1 Em = 1 x 10^{18} meters
Peta	P	10^{15}	1 Pm = 1 x 10^{15} meters
Tera	T	10^{12}	1 Tm = 1 x 10^{12} meters
Giga	G	10^{9}	1 Gm = 1 x 10^{9} meters
Mega	M	10^{6}	1 Mm = 1 x 10^{6} meters
Kilo	k	10^{3}	1 km - 1 x 10^{3} meters
Milli	m	10^{-3}	1 mm = 1 x 10^{-3} meter
Micro	µ	10^{-6}	1 µm = 1 x 10^{-6} meter

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(157) Standard for Metric Practice. ANSI/ASTM Designation E 380-76$^{\varepsilon}$, IEEE Std 268-1976, American Society for Testing and Materials, Philadelphia, Pennsylvania, February 1976. 37 pp.